

**OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION**

MEMORANDUM

January 10, 2003

TO: Dawson Lasseter, P.E., Chief Engineer, Air Quality Division

THROUGH: Phillip Fielder, P.E., Engineer Manager, Engineering Section
David Schutz, P.E., New Source Permits Section

THROUGH: Peer Review

FROM: Eric L. Milligan, P.E., Engineering Section

SUBJECT: Evaluation of Construction Permit Application No. **98-172-C (PSD)**
Valero Energy Corporation
TPI Petroleum, Inc.
Valero Ardmore Refinery – Administrative Consent Order No. 02-007
Ardmore, Carter County
Directions from I-35: east three miles on Highway 142

SECTION I. INTRODUCTION

TPI Petroleum, Incorporated (TPI), a company of Valero, currently operates the Valero Ardmore Refinery located in Carter County, Oklahoma. The applicant submitted a request for a construction permit to modify their facility in accordance with the conditions of Administrative Consent Order No. 02-007.

This permit includes the construction of control equipment proposed in the April 2000 BACT determination that was approved by ODEQ. Additionally, supplemental environmental projects (SEP(s)) are included which were within the Administrative Order. The final order includes conditions that require installation of BACT & SEP(s) equipment and implementation of NSPS & NSR standards. The major requirements are presented below:

- 1) The incorporation of a Wet Scrubber (WS) to control emissions of sulfur dioxide (SO₂) and particulate matter (PM) from the exhaust stack of the fluid catalytic cracking unit (FCCU) catalyst regenerators (BACT).
- 2) The incorporation of a scrubber to control PM emissions from the FCCU catalyst storage and receiving hoppers (BACT).
- 3) The removal of the FCCU No. 1 Regenerator Incinerator from service (SEP).
- 4) Replace the FCCU No. 1 regenerator's incinerator by installing a larger more efficient CO boiler, equipped with Low-NO_x Burners (LNB), to control emissions of CO from the FCCU No. 1 regenerator (SEP).
- 5) The existing CO boiler will be retrofitted with LNB to reduce NO_x emissions (BACT).

- 6) Continuation of the present work practice of hydrotreating the FCCU feedstock to reduce emissions of NO_x and SO₂ (BACT).
- 7) Retrofitting the crude oil preheat train indirect fired heat exchangers with Ultra Low-NO_x Burners (ULNB) (BACT).
- 8) Implementation of NSPS, Subpart GGG/VV for fugitive equipment in the Crude Unit, Amine Fuel-Gas Treating Unit, Saturated-gas Unit, Alkylation Unit, Naphtha Hydrotreating (NHT) Unit, Reforming Unit, Isomerization Unit, and Olefin Treating Unit (BACT/NSPS).
- 9) Removal of control valve sour gas vented streams (NHT-Unit, Distillate Heavy-oil Desulfurization Unit (DHDS), Saturated-gas Unit, Sour Water Stripper flash drum, and MDEA flash drum) to the East and West flare system (NSPS).
- 10) Implementation of NSPS, Subpart J, for fuel-combustion-devices (NSPS).
- 11) Implementation of NSPS, Subpart QQQ, for the crude-unit (NSPS).
- 12) Implementation of NSPS, Subpart Kb, for Sour Water #2 Stripper feedstock storage tank (T-83001) (NSPS).

SECTION II. PROCESS DESCRIPTIONS

The Valero Ardmore Refinery's primary standard industrial classification (SIC) code is 2911. The refinery processes medium and sour crude oils from both the domestic and foreign markets. Major production and processing units include the following: an 85 MBPD crude unit, a 26.2 MBPD vacuum-tower unit, a 12 MBPD asphalt blow-still unit, a 10.4 MBPD polymer modified asphalt unit, a 32 MBPD distillate heavy-oil hydro-treater (DHDS) unit, a 32 MBPD catalytic feed hydro-treater (CFHT) unit, a 30 MBPD fluid catalytic cracker unit with two-stage regeneration, a 26 MBPD naphtha catalytic hydro-treater unit, a 20 MBPD catalytic reformer unit, a 12.5 MBPD Sat-Gas Unit, a 7.5 MBPD alkylation unit, a 7.5 MBPD isomerization unit, a 98 LTPD sulfur recovery unit, and a 26 MMSCFD hydrogen production unit. The majority of raw crude oil is received on-site through utilization of an integrated pipeline system.

To effect operations, the refinery's process heaters, steam boilers, compressors, and generators are capable of producing approximately 1.6 billion BTU/hr of energy transfer. The refinery has approximately 2.4 million barrels of refined product storage capability.

Products include conventional and reformulated low sulfur gasoline, diesel fuel, asphalt products, propylene, butane, propane, and sulfur. Refined products are transported via pipeline, railcar, and tank truck.

General Function Of Petroleum Refining

Basically, the refining process does four types of operations to crude oil:

- Separation: Liquid hydrocarbons are distilled by heat separation into gases, gasoline, diesel fuel, fuel oils, and heavier residual material.
- Conversion:
 - Cracking*: This process breaks or cracks large hydrocarbons molecules into smaller ones. This is done by thermal or catalytic cracking.
 - Reforming*: High temperatures and catalysts are used to rearrange the chemical structure of a particular oil stream to improve its quality.
 - Combining*: Chemically combines two or more hydrocarbons such as liquid petroleum gas (LPG) materials to produce high grade gasoline.
- Purification: Converts contaminants to an easily removable or an acceptable form.
- Blending: Mixes combinations of hydrocarbon liquids to produce a final product(s).

Crude Unit

The Crude Unit receives a blended crude charge from tankage. The crude charge is heated, desalted, heated further, and then fed to the atmospheric tower where separation of light naphtha, heavy naphtha, kerosene, diesel, atmospheric gas oil and reduced crude takes place. The reduced crude from the bottom of the atmospheric tower is pumped through the diesel stripper reboiler and directly to the vacuum heater.

The Vacuum Unit receives a reduced crude charge from the atmospheric tower and heats it prior to entering the base of the vacuum tower. A single-stage flash vaporization of the heated reduced crude yields a hot well oil, a light vacuum gas oil, a heavy vacuum gas oil, slop wax, and a vacuum bottoms residual that may be charged to the asphalt blowstill for viscosity improvement or pumped directly to asphalt blending.

DHDS Unit

The Dehydrodesulfurization (DHDS) Unit consists of a feed section, reactor section, effluent separator section, recycle gas amine treating section, and a fractionation section. In the feed section, diesel and gas oil are fed to the unit from the Crude Unit main column. From the feed section, the mixed streams are fed to the reactor section. The feed exchanges heat with the feed/reactor effluent exchangers and is charged to the reactor charge heater. From the charge heater, the heated feed passes through a reactor bed where the sulfur and metals are removed. Once the feed leaves the reactor section, it then must be separated in the reactor effluent separator section. The hydrogen gas and hydrocarbon liquid are separated. The hydrogen gas flows to the recycle gas amine treating section where the H₂S rich gas stream is cleaned using amine to absorb the sour gas and then the hydrocarbon liquid flows to the stripping section.

In the stripping section, any H₂S that is left in the liquid hydrocarbon stream is stripped out with steam and the lighter fraction hydrocarbons are removed. Once the feed has been through the stripping section, it is preheated and fed to the fractionator tower where the kerosene, diesel and gas oil products are fractionated out to meet product specifications.

Saturated-Gas Unit

The feed to the Sat-Gas Plant is made up of crude net overhead liquid and platformer debutanizer overhead liquid. The debutanizer feed is pumped from the debutanizer feed drum to the 40-tray debutanizer. The debutanized light straight run gasoline leaves the bottom of the debutanizer and is sent to the Naphtha Hydrotreater Unit. The condensed overhead stream is pumped to the 30-tray deethanizer. Ethane, H₂S and lighter components are removed in the overhead stream and sent to the Unsat Gas Treating Area in the FCCU. The deethanizer bottoms stream that contains propane and butanes is sent to the saturate C₃/C₄ Extractor for mercaptan removal and then to the depropanizer. The condensed liquid from the depropanizer overhead accumulator is sent to the propane dryer and then to storage. The depropanizer bottoms stream is sent to the deisobutanizer located at the Alky Unit for separation of isobutane and normal butane.

Alkylation Unit

The purpose of this unit is to produce high octane gasoline by catalytically combining light olefins with isobutane in the presence of HF acid. The mixture is maintained under conditions selected to maximize alkylate yield and quality. The alkylate produced is a branched chain paraffin that is generally the highest quality component in the gasoline pool. Besides the high octane, the alkylate produced is clean burning and has excellent antiknock properties. Propane and butane are byproducts.

Naphtha Hydrotreater Unit

The purpose of this unit is to remove the sulfur, nitrogen and water from the Platformer and Penex (Isomerization) charge stocks. These are contaminants to the Platformer and Penex catalysts. This is accomplished by passing the naphtha feed stocks over hydrotreating catalyst at elevated temperatures in the presence of hydrogen at high pressures. Under these conditions, the sulfur and nitrogen components are converted to H₂S and ammonia (NH₃), which are then easily removed from the liquid effluent by distillation stripping. The removal of the contaminants provide clean charge stocks to the Platformer and Penex units which increases the operational efficiency of both units.

Platformer Unit

The purpose of this unit is to upgrade low octane naphtha to higher octane gasoline blending stock. The naphtha is a specific boiling range cut from the Crude Unit. The naphtha is upgraded by using platinum catalyst to promote specific groups of chemical reactions. These reactions promote aromatic formation, which gives the boost in octane. A byproduct from the reactions is hydrogen, which is used to support the operation of the reformer feed preparation and throughout the refinery. The reactions also produce light hydrocarbon gases which are used to regulate the vapor pressure of the reformate. The balance of the light hydrocarbons is recovered as LPG for sales and as refinery fuel gas.

The continuous catalyst regeneration (CCR) section of the Platformer Unit allows the reaction section to operate efficiently while maintaining throughput year round. The CCR continuously regenerates a circulating stream of catalyst from the reactors. During normal operations in the reaction section, catalyst activation is lowered due to feedstock contaminants and coke buildup. The regeneration section continuously burns off the coke deposit and restores activity, selectivity and stability to essentially fresh catalyst levels. The contaminants can be controlled by proper feedstock preparation and operating conditions.

Isomerization Unit

The purpose of the unit is to increase the octane of light naphtha. The octane is increased by catalytically rearranging straight chain hydrocarbons to branched hydrocarbons. This process is called "isomerization" and thus the unit is usually referred to as the Isom Unit. The bulk of the products from the unit is the isomerate (C₅'s and C₆'s), which are added to the refinery gasoline pool. The advantage of using isomerate is good motor octane, benzene saturation and aromatic reduction. There will be a small yield of light hydrocarbons, which are added to the refinery fuel gas system.

Cat Feed Hydrotreater

Hydrotreating is a process to remove impurities present in hydrocarbons and/or catalytically stabilize petroleum products by reacting them with hydrogen. The cat feed hydrotreater has two primary functions: 1) improve the quality of the feed to the FCCU by removing impurities (metals, sulfur, and nitrogen), and 2) increasing the hydrogen content by saturating the aromatics in the gas oils and light cycle oil feedstocks.

Feed to the cat feed hydrotreater enters the unit from several sources: high sulfur diesel from 81 Tank; light cycle oil from the FCCU; gas oil from the Crude Unit; either vacuum or atmospheric residue from the Crude Unit; and hydrogen from the Hydrogen Unit. The combined liquid feed is filtered and then heated in a series of exchangers before entering the feed surge drum. Liquid feed from the surge drum is pumped to the reaction section of the unit through the multistage charge pump. Hydrogen feed is compressed to the unit operating pressure by two reciprocating compressors. The fresh hydrogen feed along with recycled hydrogen from a steam turbine driven centrifugal compressor combines with the liquid feed in the reaction section of the unit.

Combined feed to the unit is heated in the reactor charge heater and then enters the first of three reactors in series. The reactors each contain a different type of catalyst with a very specific, but complementary role. The primary role of the catalyst in the first two reactors is to remove metals contained in the feed such as nickel and vanadium. The catalyst in the third reactor is primarily designed to convert sulfur and nitrogen species into a form in which they can be removed. The effluent from the reactors then enters a series of separators.

There are four separators in the cat feed hydrotreater: Hot High Pressure Separator, Hot Flash Drum, Cold High Pressure Separator, and Cold Flash Drum. The primary function of these vessels is to separate the oil from the hydrogen-rich gas in the reactor effluent. Each vessel is operated at different conditions (temperature and pressure) to allow certain components in the reactor effluent to vaporize. Hydrogen recovered in the cold high-pressure separator is routed to the recycle gas amine treater. Light ends, such as methane and ethane, are sent to the refinery sour fuel gas system. Water recovered is sent to a sour water stripper. All of the remaining oil is then combined and sent to the fractionation section of the unit.

Hydrogen recovered from the reactor effluent contains H_2S . The unit is designed to have 0.5-1.0% H_2S in the recycle gas. To control the H_2S at the desired level, a portion of the recycle gas is amine treated. Recycle gas enters the bottom of the amine absorber and is contacted by a counter-current flow of amine across trays. The H_2S is absorbed by the amine and sweet hydrogen exits the top of the absorber. Amine exits the bottom of the absorber and is regenerated in the amine unit in the refinery.

The oil from the separators is routed to the fractionation section of the unit. The oil is heated in the fractionator charge heater and then enters the fractionator. The fractionator is a trayed tower. The fractionator separates the oil into three streams: overhead naphtha product; diesel product; and FCCU feed. The diesel product is stripped of light ends and H_2S in the distillate stripper before being sent to storage.

FCCU

The main purpose of the Fluidized Catalytic Cracking Unit (FCCU) is to break up heavy hydrocarbons into a mixture of lighter hydrocarbons and then separate the mixture. The major divisions of the plant are the FCCU Charge System, the Reactor-Regenerators, the Main (Fractionator) Column, and the Gas Concentration Unit.

In the FCC Charge System, the feed is collected and heated before it is sent to the FCC Unit. The feed comes from four sources: residuum from the Vacuum Tower, treated gas oil from storage, gas oil from the Crude/Dehydrodesulfurization (DHDS) unit, and hot gas oil from the Cat Feed Hydrotreater (CFHT) Unit. The hot and cold charge streams are mixed in the charge drum to reach a desired temperature. The outlet stream from this drum combines with the residuum stream and is pumped through the charge heater where, if necessary, the feed is heated. Finally, the feed is sent to the FCCU reactor for processing.

The catalytic cracking for the process is done through the heat of the catalyst in contact with the feed. As a result, the catalyst is covered with coke which must be burned off the catalyst in the FCCU No. 1 and No. 2 regenerators. This burning process results in temperatures normally above 1,300 °F. The hot catalyst is recirculated through the system to mix with more feed to control the reactor temperature.

The cracked gas oil must be separated into useable products, namely slurry or #6 fuel oil, light cycle oil (LCO) or diesel fuel, FCCU gasoline or blend stock for motor gasoline and light liquefied petroleum gases (LPG) including olefins.

MDEA Unit

Methyldiethanolamine is used to recover CO₂ and H₂S to form a weak and unstable salt. These processes take place in the fuel gas absorber and amine contactors. Once this weak and unstable amine salt solution is formed, the reaction must be reversed to clean up or regenerate the amine solution. This reaction takes place in the MDEA Regenerator.

The MDEA solution is fed to the tower from the MDEA Flash Drum. As the solution travels down the tower, the acid gases are stripped as the salt solution is broken down by heat, which is supplied by two steam reboilers at the base of the tower. The lean regenerated MDEA is then pumped back to the Lean MDEA Surge Drum where the low- and high-pressure MDEA charge pumps charge the regenerated amine solution back to the fuel gas absorber and amine contactors.

Sour Water Strippers

The purpose of the sour water strippers are to remove H₂S and ammonia from the total sour water inlet stream. The H₂S and ammonia are stripped from the sour water feed as the water travels down the column. Rising steam strips out the H₂S and ammonia gases. These gases are routed to the SRU/SCOT Unit to convert the H₂S gas stream to sulfur and to destroy the ammonia gas in the thermal section of the SRU.

SRU / SCOT Process

The SRU converts the H₂S stream from the MDEA Regenerator to liquid elemental sulfur to be loaded out by rail car or truck. This process takes place in two general sections: 1) H₂S is converted to sulfur at high temperatures without the aid of catalytic conversion; and 2) sulfur is formed at much lower temperatures with the aid of catalytic conversion.

In section one, high thermal temperatures are maintained by using liquid oxygen, which also aids in the destruction of ammonia contained in the sour water gases which are destroyed in the thermal section of the SRU. In section two, unconverted sulfur is processed through two successive catalytic stages. Each stage consists of process gas reheating, sulfur conversion over an activated alumina catalyst and then cooling to condense and recover the sulfur formed.

The SCOT Unit operation is much the same as the MDEA Unit operation. Unprocessed tail gas from the SRU is heated and mixed with a hydrogen rich reducing gas stream. This heated tail gas stream passes through a catalytic reactor where the sulfur compounds are reconverted back to H₂S. Once the tail gases are converted back into a H₂S gas stream, these gases are routed to a quench system where the gases are cooled and the condensed water from the reactor product is routed to the sour water system. The cooled reactor effluent is then fed to an absorber/stripper section where the acid gas comes in contact with an amine solution and is absorbed and then regenerated to be reprocessed back to the SRU.

Wastewater Treatment Plant

The WasteWater Treatment Plant is for the purpose of treating refinery wastewater from the various units and tank farm to comply with specific discharge characteristics specified by the refinery National Pollution Discharge Elimination System Permit. The system is comprised of an oily water sewer collection system from the various units and the tank farm, a lift station, two above ground oil water separation tanks, two aggressive bio-reaction tanks, 16 aerated lagoons and two clarifier lagoons. Flow through the system from beginning to discharge is as stated above. The system treats approximately 600,000 gallons of wastewater daily.

Product Movement Tank Farm

The purpose of the tank farm and product movement area is to receive, hold, blend, and ship hydrocarbon products in a safe and efficient manner. The major product groups include crude, intermediate feedstocks, LPG, gasolines, distillates, heavy fuel oil, and asphalts. Distillate and gasoline products are shipped via three outlets. These products are also loaded onto trucks at the truck dock. Various LPG's are loaded and unloaded by truck and rail. Asphalt and heavy fuel oil are primarily shipped by truck, but rail connections can also be used.

SECTION III. BACKGROUND CONCERNING MODIFICATIONS**Background of the 1976 Replacement of the East Flare**

The 1974 construction Permit No. 74-171-O serves as a beginning point to assess emissions from the crude unit, FCCU, and VGO unit. The flare that serviced these areas was reconstructed in approximately 1952 to flare excess pressure released gases. In 1976, the flare was replaced with a more efficient flare. Replacement of the East Flare subjected it to the relevant provisions and standards of NSPS, specifically Subparts A (General Provisions) and J (Petroleum Refineries).

Background of the 1980 Construction of the Reformer Unit's CCR

Prior to the installation of the continuous catalyst regenerator (CCR) in 1980, the unit regenerated the catalyst by shutting the unit down, purging the reactors, and burning the coke accumulated on the catalyst. The disadvantage to this approach is that the unit had to be shutdown for catalyst regeneration. The reformer CCR equipment includes a catalyst collector (V-417), two lock hoppers (V-418 and V-424), a lift engager (V-419), four vent drums (V-429, V-428, V-432 and V-433), an organic chloride storage vessel (V-435), a disengaging-hopper (V-420), a regeneration tower (V-421), a flow control hopper (V-422), a surge hopper (V-423), an air dryer (DRY-401), a dust collector (V-430), four electric heaters (H-408, H409, and H-410(A&B)), a knock out drum (V-431), and four air-blowers (C-403, C-405, C-407, and C-406). The fugitive equipment installed includes 136 valves in gas service, 54 valves in light-liquid service, four pressure relief valves (PRV(s)) vented to the flare line, and five PRV(s) not routed to the flare. The CCR was later permitted under Permit No. 98-265-O. The modifications prior to Permit No. 98-265-O required a PSD permit based on the potential emissions changes associated with the modifications.

Background of Pre/Post- 1981-82 Construction/Modifications of the FCCU

Utilizing Permit No. 74-171 as a basis for origination, the FCCU was permitted to process 20,000 bbl/day of fresh feed. The original design of the FCCU included one reactor and one catalyst regenerator. Energy recovery produced steam using two heat exchangers arranged in parallel and processing the regenerator flue gas.

In 1981, the FCCU was redesigned. The modifications to the FCCU were so extensive that the scope could be classified as new construction. The modifications included: replacement of the reactor and regenerator and the addition of another regenerator, a 15 MMBTU/hr incinerator, three catalyst storage hoppers, four external cyclones, internal tertiary cyclones, a withdrawal well, 46 heat exchangers, four compressors, 10 towers, 21 pressure vessels, 17 mixers, 40 pumps, a reactor, 2 regenerators, and two air pre-heaters rated at 60 and 75 MMBTU/hr. In addition to these installations, the supporting piping (valves, flanges, prv(s), etc...) was also installed. Construction began around July 1981 and was completed in June 1982. The modifications increased the capacity of the FCCU to 25,000 bbl/day. Although the CO boiler was not installed until 1984, the scope of this modification also incorporated the CO boiler.

The FCCU was modified twice after the 1981-82 modification to increase the feed rate of the FCCU up to 27,550 bbl/day and then to 30,000 bbl/day. The consent order stated that the FCCU was modified in 1995. In 1998, the refinery was issued Permit No. 98-228-C, which authorized repair work on the FCCU main column. Permit No. 98-228-C limited the FCCU charge rate to the charge rate reported in the 1997 emission inventory of 9,300,000 bbl/yr with a maximum of 27,550 bbl/day. In the application for Permit No. 98-228-O, the applicant stated that the actual FCCU charge rate for 1997 based on refinery throughput records was actually 9,404,400 bbl/yr not 9,300,000 bbl/yr. Since this limit was established to ensure that the repair project would not trigger PSD requirements, the applicant requested that the limit be established based on 1998 throughput data for the month prior to the main column repair work. The applicant stated that the FCCU was then operated at a monthly average charge rate of 26,524 bbl/day and requested a limit of 9,640,000 bbl/yr with a sulfur limit of 0.265% by weight in the feedstock. The limit on the feedstock sulfur content would ensure that SO₂ emissions would not increase above the 1997 reported emissions. The consent order required the FCCU to comply with the 12-month rolling average throughput of Permit No. 98-229-C as long as that permit remained in effect. This permit will establish a new daily and annual throughput limit for the FCCU of 30,000 bbl/day and 9,640,000 bbl/yr based on information in the BACT analysis.

The modifications prior to Permit No. 98-228-C required a PSD permit based on the potential emissions changes associated with the modifications. In addition, the modifications were also subject to the relevant provisions and standards of NSPS, specifically Subparts A (General Provisions), J (Petroleum Refineries), and GGG (Equipment Leaks of VOC in Petroleum Refineries).

Background of 1981-82 Construction/Modification of FCCU Catalyst Receiving Hoppers

The original design of the catalyst storage hoppers was documented in the 1952 design specifications and drawings. The system consisted of two catalyst storage hoppers that were able to receive and unload catalyst. These vessels were designated as V-1 (main catalyst storage

hopper) and V-2 (auxiliary catalyst storage hopper). In 1959, 2nd stage cyclones were added to the flue gas system. In 1974, there were no modifications made to the catalyst hoppers.

In the 1981 FCCU expansion, several modifications were incorporated within the catalyst processing and recovery system, to include the flue gas processing system. The modifications to the existing catalyst hopper system included the addition of a catalyst hopper. This hopper was in spent catalyst service. The refinery retained the two existing hoppers as a secondary spent catalyst hopper and a fresh catalyst hopper.

The modifications to the overall system involved the hopper addition and piping/routing of the system. Each hopper was equipped with an atmospheric vent and steam was utilized to pneumatically convey the catalyst and as a wetting agent. Subsequent modifications (Post-1981 modification and construction) of the system included process throughput increases and installation of a cyclone on the atmospheric vents. The modifications required a PSD permit based on the potential emissions changes.

Background of 1984-85 Construction of CO Boiler

Design engineering for the CO Boiler began around July 1984. Construction activities began in the latter parts of 1984 and were completed in 1985. The packaged boiler was purchased to recover energy losses associated with the incomplete incineration of flue gases containing carbon monoxide from the FCCU No. 1 Regenerator. The original design basis for the CO boiler was established at a heat input of 91.6 MMBTU/hr (HHV) operating at approximately 81% efficiency. This produced approximately 65,000 lbs of steam per hour for utilization in the refinery. The boiler utilizes two types of fuel. Flue gas is the primary fuel and refinery fuel gas is used as an auxiliary fuel.

The construction and subsequent operation of the CO boiler required a PSD permit based on the potential emissions changes associated with the modification. In addition, the modification was also subject to the relevant provisions and standards of NSPS, specifically Subparts A (General Provisions) and J (Petroleum Refineries).

Background of the 1987 Modification of the Reforming Unit

The reformer unit was reconstructed within the scope of the 1974 plant-wide reconstruction activities. The original design of the unit consisted of two phases: the naphtha hydro-treating and the reforming units. These areas are designated as the 400 series within the refinery. The reforming unit was modified in 1987 to incorporate one additional heater (H-411 at 28 MMBTU/hr), a reformer off-gas LPG recovery system which consisted of a stand alone ammonia refrigeration unit operation (two compressors, a lube oil system, four-exchangers, a receiver, and a oil separator), an absorption tower, an overhead receiver, a sulfur guard bed, three light-liquid-pumps, four heat-exchangers and two PRV(s). For the reformer portion of the modifications, approximately 57 valves in gas service, 122 valves in light liquid service, and 300 flanges were installed as peripheral piping equipment support.

Additionally, the complete isomerization unit was added at this time. The equipment installed for the isomerization unit included three UOP Penex reactors, a stabilizer, an absorber, four accumulators, two dryers, 20 heat exchangers, three compressors, and five pumps. The

supporting fugitive equipment installed per this addition included 761 valves (682 in light liquid service and 79 in gas service), 1,294 flanges, and 14 PRV(s). This modification subjected the reforming unit to the relevant provisions and standards of NSPS, specifically Subparts A (General Provisions) and GGG (Equipment Leaks of VOC in Petroleum Refineries).

Background of 1990 Crude Unit Refurbishment

The original design capacities for Heaters H102A and H102B were established in 1961 and 1974 at approximately 100 MMBTU/hr and 63 MMBTU/hr, respectively. AFE No. 106123 dated May 15, 1989 approved expenditures for projects concerning the refurbishment of these crude unit heaters. The refurbishment incorporated replacement of the burners and modifications to the convection section that enabled the refinery to process crude oil at an increased capacity. The present rating of H102A and H102B are determined to be 145 and 135 MMBTU/hr. The refurbishment activities included modifications to product transfer equipment (pumps, valves, flanges, PRV(s)) and to the refinery oily water sewer system.

These modifications of the existing equipment required a PSD permit based on the potential emissions changes associated with the modifications. In addition, the modifications were subject to the relevant provisions and standards of NSPS, specifically Subparts A (General Provisions), J (Petroleum Refineries), GGG (Equipment Leaks of VOC in Petroleum Refineries), and QQQ (VOC Emissions from Petroleum Refinery Wastewater Systems).

Background of the pre/post-1990 Modifications of the Alkylation Unit

The original alkylation unit was constructed in 1957. The unit was then reconstructed in 1973. The reconstruction activities of 1973 serve as a beginning basis of estimating emission and potential emission changes for the alkylation unit.

Utilizing the FCCU debutanizer overhead accumulator as a starting point (alkylation feed drum) for the alkylation unit, the equipment per the post-1973 construction included an alky feed a MEROX and a DEA absorber, two reactors, a HF acid mixer/settler, an iso-stripper, a heater (H-901), an iso-stripper receiver, a de-propanizer feed-settler, a depropanizer, a de-propanizer overhead accumulator, a HF regeneration column, a HF stripper, two alumina-treaters, two KOH scrubbers, a CBM drum, a HF neutralizing drum, a KOH mix tank, a relief-gas-scrubber, 21 heat exchangers, 11 pumps, 19 PRV(s), and an associated amount of valves and flanges.

The modifications of the alkylation unit in 1978, 1981, 1984, 1987, 1991 included the installation of a butane HF treating system and other modifications to enable more efficient processing and acid control/product recovery. These modifications subjected the Alkylation Unit to the relevant provisions and standards of NSPS, specifically Subparts A (General Provisions) and GGG (Equipment Leaks of VOC in Petroleum Refineries).

Background of the 1991 Reconstruction of the Refinery's West Flare

The original West flare was constructed in approximately 1952. The flare was reconstructed in 1991. The emissions change resulting from the reconstruction are addressed in Permit 91-160-C (effective April 16, 1992) with accompanying Evaluation of Permit Memorandum. Replacement of the West Flare subjected it to the relevant provisions and standards of NSPS, specifically Subparts A (General Provisions) and J (Petroleum Refineries).

Background of the 1993 Construction of the Reforming Heater H-15001

The application to construct the Reforming Heater H-15001 was filed with ODEQ on December 23, 1991. Permit No. 91-160-C, effective April 16, 1991 enabled the refinery to construct equipment and perform operational modifications within the crude, DHDS, CFHT, SRU, and sour water system. These modifications enabled the refinery to produce low-sulfur (0.05 wt%) diesel fuels. The modifications incorporated the netting procedures utilized in PSD reviews and became federally enforceable as such. The Air Quality permit memorandum for Permit No. 91-160-C, dated April 16, 1992, detailed the review.

The Air Quality permit memorandum for Permit 91-160-O, effective July 21, 1995, provides the basis of emissions. The basis included supplemental information received on February 3, March 6, and April 3, 1992, August 1, 1994, and July 21, 1995. Permit No. 95-506-O superceded permit No. 91-160-O, which was then null and voided by Permit No. 95-506-O (M-1). The Reforming Heater is subject to the relevant provisions and standards of NSPS, specifically Subparts A (General Provisions) and J (Petroleum Refineries).

Background of 1993 Modification of the Refinery's Fuel-Gas Amine Treating System

The amine solution H₂S absorption system, by methyldiethanolamine (MDEA), was constructed prior to 1974 and was later re-constructed in 1974 to control, and regulate, the concentration of H₂S and SO₂, within the refinery's fuel gas system. The fuel gas system delivers fuel to the refinery's combustion devices. Primarily, the H₂S absorption process was installed to reduce the emissions of SO₂. Secondly, the system was designed to work in conjunction with the sulfur recovery unit to produce elemental sulfur.

Utilizing the post-1974 construction activities (pre-1993 modification) as a basis for a permitted system, the original design of the amine system included a rich amine flash drum (V-551), an absorber feed drum (V-552), an absorber off-gas drum (V-553), an amine regenerator overhead accumulator (V501), an acid gas scrubber (V-502), a tail gas coalescer (V503), a fuel gas absorber (T-551), a lean amine surge tank (TK-551), 8 pumps, 7 heat exchangers, and 2 filters. The system received humidified sour gas streams from the DHDS, CFHT, Sat-Gas, and Alkylation units. The system discharged sour water directly to the oily water sewer system at that time which was then discharged to Sand Creek.

In 1993, a new rich amine flash drum (V-55005) was installed to replace (V-551) to allow for increased throughput/accumulation capacity and to provide enhanced feed surge protection to T-501. As with the original V-551, V-55005 was vented to the flare by a back pressure regulated control valve. Six pumps were also installed to accommodate service and operation for the flash drum. An amine sump (V-55006) and pump were installed as well with this modification. The actual piping equipment installed for this modification is approximately 120 valves in light liquid service, 30 valves in gas service, 1 PRV, and 260 flanges. Permit 93-101-O issued by ODEQ addressed construction of the flash drum. The permit required the gases from the amine flash drum amine wash system to be vented to a flare or an equally effective means of control. These modifications subjected the Refinery Fuel Gas Amine Treating System to the relevant provisions and standards of NSPS, specifically Subparts A (General Provisions) and GGG (Equipment Leaks of VOC in Petroleum Refineries).

Background of the 1993 Sat-Gas Plant's LPG Amine Contactor Addition

The Saturated-Gas Plant was constructed in the 1974 refinery-wide reconstruction activities. The saturated-gas-plant after the 1974 construction consisted of an indirect-fired heat exchanger (H-301), 25 heat exchangers, 17 pumps, 5 towers (T-301, T-302, T-303, T-304, & T-305), and 5 vessels (V-301, V-302, V-303, V-304, & V-305). In addition to this equipment was the fugitive equipment of valves, flanges, and PRV's.

The application to construct the LPG amine-contactor (T-306) was submitted to ODEQ on July 21, 1993. This addition to the Sat-gas Plant enabled the refinery to process a sweet LPG feedstock to the alkylation unit and for sale.

Permit 93-076-O issued by ODEQ, effective July 26, 1994, authorized the refinery to construct and operate the LPG amine contactor (T-306) within the Sat-gas plant. The unit was designed to process 3,600 bbl/day of LPG with a maximum anticipated sulfur content of 5,000 ppm sulfur down to a sulfur content of 5 ppm, for a total of 4,591 lb/day of sulfur in the feed being sent to the contactor. The permit required the gases from the amine contactor to be vented to the existing SRU, or an alternative control device with an efficiency of 99.5%. These modifications subjected the Sat-gas plant to the relevant provisions and standards of NSPS, specifically Subparts A (General Provisions) and GGG (Equipment Leaks of VOC in Petroleum Refineries).

Background of the 1993 Construction of the Refinery's Diesel-Fired Air Compressor

The installation of the 400-hp Cummins Model 8083-7400 diesel-fired air compressor occurred in March of 1993. It was the intent of the refinery to limit the operation of the compressor to less than 500 hours per year since the compressor's function was to supply emergency air to refinery process control instruments. The original installation was interpreted to meet insignificant activity criteria, but the operations of the compressor were subsequently modified to increase the hours of operation above that which is conditioned by the criterion classifying an insignificant activity. The procedures and methodology to account for the hours of operation were not established and some historical operational interpretations indicated that the compressor operated more than 500 hours per year. Based upon the historical interpretations of operation, in conjunction with the non-compliance issues identified within the Title V permit application development, it was determined that the emergency air compressor should be limited to 4,000 hours of operation.

The refinery submitted a minor source application permit to operate the compressor on August 24, 1998, with a limit of 4,000 hours of operation per year. Permit 98-229-O, effective December 17, 1998, authorized the refinery to utilize the compressor in emergency air situations with a limit of 4,000 hours a year operation. However, installation of the diesel-fired air compressor would have required a PSD permit based on the potential emissions changes associated with the modification. This permit will address the modification in the context of PSD.

Background of the 1993 Addition of the Sour Water Stripper Feed Tank (T-83001)

Construction of the No. 2 sour-water stripper feed tank T-83001 began in 1993. The tank was placed in operation in 1994. The tank stores sour waters received from the NHT, DHDS, and CFHT units within the plant. The tank is operated in manner to ensure that a barrier fluid, diesel,

is maintained on the liquid surface of the water at all times to control emissions of VOC and hydrogen sulfide. ODEQ Permit No. 95-506-O (M-1), effective October 1, 1998, permits the operation of this storage tank. This tank is subject to the relevant provisions and standards of NSPS, specifically Subparts A (General Provisions) and Kb (VOL Storage Vessels). Permit No. 95-506-O (M-1) was based on a throughput of 2,565,500 bbl/yr.

Background of the 1994 Modification of the Refinery's Olefin Treating Unit

The 1994 modification to the FCCU's olefin treating unit included the complete replacement of the LPG amine contactor located within the alky unit. The refinery submitted an application for the modified olefin treating process in September 1998, to reflect the current operation. Air Quality issued Permit 98-264-O on December 2, 1998, authorizing operation of the Olefin Treating Unit. These modifications subjected the Olefin Treating Unit to the relevant provisions and standards of NSPS, specifically Subparts A (General Provisions) and GGG (Equipment Leaks of VOC in Petroleum Refineries).

Background of the 1994 Construction of Blowstill Incinerator HI-801

Permit Application No. 91-160-C included a request to replace the existing incinerator that was in use at that time with a new incinerator with an equivalent capacity. Permit No. 91-160-C, effective April 16, 1992, approved the construction and modification activities. The PSD review was based on federally enforceable limitations established by the formal netting procedures included in the application. The review detailed the overall contemporaneous emission increases. All emission increases were below the significance levels.

Permit No. 91-160-O, effective July 21, 1995, addressed the actual construction and modifications that occurred within the scope of the application. The application for operation of the facilities modified or constructed during the project as conditioned by Permit No. 91-160-C was submitted to ODEQ. Permit No. 95-506-O superseded Permit No. 91-160-O, which was then voided by Permit No. 95-506-O (M-1). A follow-up PSD netting review (operating permit application) indicated that the adjustments to the information originally submitted (construction permit application versus actual/potential operating permit application) resulted in less than significant emission(s) increases for criteria pollutants, as well. The Blowstill Incinerator is subject to the relevant provisions and standards of NSPS, specifically Subparts A (General Provisions) and J (Petroleum Refineries).

Background of the 1994 Construction of Emergency Generators EEQ-8801 & EEQ-80001

The installation of the 750-kW Detroit DMT D Model 16V92TA diesel-fired emergency generator EEQ-8801 occurred in 1994 to operate the WWTP in the event of a power outage. Air Quality Permit No. 97-523-O, effective March 24, 1998, authorized the operation of this generator. Permit No. 97-523-O also authorized the operation of an 80-kW Onan DGDA emergency generator with a Cummins 6BT5.9-G1 diesel engine. Generator EEQ-80056 started to operate in January 22, 1998, and is used to power the main control room, in the event of a power outage, to give operation personnel sufficient time to safely shut the units down. The engines operated without a permit until issuance of Permit No. 97-523-O. The permit authorized each of these generators to be operated up to 200 hours per year for maintenance checks and possible power outages and with a maximum fuel sulfur content of 0.5% by weight.

Background of the 1995 Modification of Platform Heaters

Heaters H-404 and H-405 were modified in 1995 to be fueled with two types of fuel: natural gas and vent gas from the CCR Reformer. Since the modification increased emissions from the heaters, they became subject to the relevant provisions and standards of NSPS, specifically Subparts A (General Provisions) and J (Petroleum Refineries).

The facility also requested that heaters H-401A, H-401B, H-402A, H-402B, H-403, H-407, and H-407 and boilers B-802 and B-803 to be included in the permit. The heaters and boilers were originally presented to ODEQ utilizing the LHV (651 BTU/SCF) for the maximum firing capacity. The adjustment factor to arrive at the HHV is approximately 1.115. The permit will reflect the heat input rating for these heaters and boilers and establish emission limits for them.

Background of the 1996 Construction of the Loading Dock Vapor Incinerator

In order for the gasoline loading operations to comply with NESHAP, Subpart CC, and Subparts A and R, the refinery was required to install a vapor incinerator at the gasoline and diesel loading rack. The refinery submitted the application for the incinerator on September 6, 1996. The refinery received Permit No. 96-450-C, effective October 17, 1996, authorizing construction of the vapor incinerator. On April 28, 1997, the refinery submitted an application to operate the vapor incinerator and on May 30, 1997, Air Quality issued Permit No. 96-450-O, approving operation of the vapor incinerator. The permit memorandum for Permit No. 96-450-O, dated May 28, 1997, addressed the regulatory requirements and emission(s) quantification(s) methodology. The lb/hr emissions were based on a throughput of 5,400 gallons/minute of gasoline and 1,500 gallons/minute of distillate fuel oil. Annual emissions were limited to 52 TPY or approximately 3,015 hr/yr at the maximum pumping rate. The Loading Dock Incinerator is subject to the relevant provisions and standards of NSPS, specifically Subparts A (General Provisions) and J (Petroleum Refineries).

Background of the 1996 and 1998 Construction of Hot-Oil-Heaters H-100024 & H-210001

Heater H-20001 was installed in 1996, as authorized by Permit No. 96-402-C (M-1), and was due to the installation of the PMA unit at the refinery. Construction for heater H-100024 began in 1998, as authorized by Permit No. 98-172-C, to integrate a hot-oil heating system into the asphalt storage tank area; this heater replaced certain individual tank heaters and enabled more efficient energy utilization. These units are subject to the relevant provisions and standards of NSPS, specifically Subparts A (General Provisions) and Dc (Small Industrial-Commercial-Institutional Steam Generating Units).

Alternative Monitoring Plan (AMP) for NSPS, Subpart J

Enclosed with the application was an AMP for the following fuel gas streams to fuel gas combustion devices to ensure compliance with the NSPS, Subpart J refinery fuel gas combustion device standard of 230 mg/dscm (0.10 gr/dscf).

- PSA Off-gas to H-15001
- Light Products Loading Rack Vapor Combustor
- Recycle Hydrogen (H₂) to Isomerization Unit Drier Vents
- H₂ to Reformer CCR
- Vent gas from the Reformer CCR to Heaters H-404 and H-405

The AMP was also submitted to U.S. EPA Office of Air Quality Standards and Planning who has the ability to approve AMPs for NSPS Standards.

SECTION IV. AFFECTED EQUIPMENT - EMISSION UNIT (EU) GROUPS

EUG 49 Sour Water Stripper Tank T-83001

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-83001	P-56	Cone	Sour Water	18,500	1993

EUG 101 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-102B	P-102	Process Heater	135.0	Mod. 1990

EUG 102 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-102A	P-103	Process Heater	145.0	Mod. 1990

EUG 103 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-403	P-104	Process Heater	98.7	1975

EUG 104 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-404	P-105	Process Heater	48.0	Mod. 1995

EUG 105 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-405	P-106	Process Heater	50.3	Mod. 1995

EUG 106 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-406	P-107	Process Heater	28.0	1974

EUG 115 Process Flare (East)

EU	Point	Description	Const. Date
crude unit flare	P-116	Process Flare	1976

EUG 116 Asphalt Blowstill and Thermal Oxidizer

EU	Point	Description	Const. Date
HI-801	P-117	Asphalt Blowstill and Thermal Oxidizer	1992

EUG 118 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-201	P-119	Process Heater	104.7	1974

EUG 120 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-401A	P-121	Process Heater	16.0	< 1968

EUG 121 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-401B	P-122	Process Heater	17.0	1974

EUG 122 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-402A	P-123	Process Heater	13.8	< 1968

EUG 123 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-402B	P-124	Process Heater	15.9	< 1968

EUG 124 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-407	P-125	Process Heater	25.0	1974

EUG 126 Boiler

EU	Point	Description	MMBTUH	Const. Date
B-802	P-127	Boiler	77.8	1975

EUG 127 Boiler

EU	Point	Description	MMBTUH	Const. Date
B-803	P-128	Boiler	75.9	1975

EUG 128 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-411	P-129	Process Heater	28.0	1985

EUG 134 Refinery Flare (West)

EU	Point	Description	Const. Date
HI-81001	P-135	Platformer and Alkylation Units	1993

EUG 138 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-15001	P-139	Process Heater	293.3	1992

EUG 139 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-210001	P-140	Process Heater	12.2	1996

EUG 140 Gasoline Loading Rack Vapor Combustor

EU	Point	Const. Date
Light Products Loading Terminal	P-141	1996

EUG 141* FCCU Flue Gas Scrubber

EU	Point	Description	Const. Date
FGS-200	P-142	FCCU No. 1 Regenerator/CO Boiler and FCCU No. 2 Regenerator	2002-3

* - EUGs 141A, 141B, and 141C, will all be vented to this EUG and point upon completion of the modifications. EUG 145 will either be vented to this EUG or another wet scrubber.

EUG 141A FCCU No. 1 Regenerator and CO Boiler/Incinerator

EU	Point	Description	Const. Date
HI-251	P-143	FCCU No. 1 Regenerator and CO Boiler/Incinerator	Mod. 1996

EUG 141B CO Boiler

EU	Point	Description	MMBTUH	Const. Date
B-252	P-143	CO Boiler	92.0	1984
B-253	P-143	CO Boiler	125.8	2002-3

EUG 141C FCCU No. 2 Regenerator

EU	Point	Description	Const. Date
R-251	P-142	FCCU No. 2 Regenerator	Mod. 1996

EUG 143 Emergency Generators

EU	Point	Make/Model	KW	Serial #	Const. Date
EEQ-8801	P-145	DMT/DMT-825D2	750	93447-1	1994
EEQ-80001	P-146	Cummins/6BT5.9G-2	80	45555233	1997

EUG 145 FCCU Catalyst Hopper Vent

EU	Point	Description	Const. Date
cat_hop	P-149	FCCU Catalyst Hopper Vent	Mod. 1981

EUG 146 Platformer Catalyst Regeneration Vent

EU	Point	Description	Const. Date
CCR	P-150	Platformer Catalyst Regeneration Combustion Vent	1980

EUG 147 Instrument/Plant Air Compressor

EU	Point	Make/Model	hp	Serial #	Const. Date
C-80018	P-151	General/250004-A36	400	69102	1993

EUG 148 Asphalt Tank Heater

EU	Point	Description	MMBTUH	Const. Date
H-100024	P-152	Asphalt Tank Heater	13.5	1999

EUG 200 Crude Unit Fugitive Sources

EU	Point	Number Items	Type of Equipment
Area 100	F-100	2,338	Valves
		3,876	Flanges
		15	Other
		46	Pumps

EUG 205 Amine Fuel Gas Treating System Fugitive Sources

EU	Point	Number Items	Type of Equipment
Area 550	F-105	403	Valves
		677	Flanges
		4	Other
		11	Pumps

EUG 206 Sat. Gas Plant Fugitive Sources

EU	Point	Number Items	Type of Equipment
Area 300	F-106	835	Valves
		1,389	Flanges
		12	Other
		7	Pumps

EUG 207 Reformer "Platformer" Fugitive Sources

EU	Point	Number Items	Type of Equipment
Area 400	F-107	2,074	Valves
		3,488	Flanges
		23	Other
		16	Pumps

EUG 208 Isomerization Unit Fugitive Sources

EU	Point	Number Items	Type of Equipment
Area 450	F-108	786	Valves
		1,294	Flanges
		17	Other
		5	Pumps

EUG 211 HF Alkylation Unit Fugitive Sources

EU	Point	Number Items	Type of Equipment
Area 900	F-111	2,295	Valves
		3,803	Flanges
		23	Other
		31	Pumps

EUG 214 Wastewater Treatment Unit Fugitive Sources

EU	Point	Number Items	Type of Equipment
ASU	F-114	154	Valves
		258	Flanges
		---	Other
		6	Pumps

EUG 219 Olefin Treating Unit Fugitive Sources

EU	Point	Number Items	Type of Equipment
Area 250	F-119	1,118	Valves
		969	Flanges
		5	Other
		12	Pumps

SECTION V. EMISSIONS

The implementation of NSPS and OAC 252:100 new source review (NSR) standards in conjunction with PSD standards has resulted in a significant reduction of the emissions of criteria pollutants at the refinery. The table below provides the overall pre-PSD and post-PSD review emissions when considering the time-frame of activities identified within this review as identified in the order and the respective permitted standards. The quantification of these emissions and the assumptions utilized are discussed in detail in this section. These emissions are not presented in exactness as a conclusive determination, but rather are an attempt to represent the magnitude of the effectiveness of the review. Emissions from the facility were based on an extensive assessment of the modifications to the refinery, the applicable standards, and the equipment involved.

The table below provides a list of active permits, registrations, and applicability determinations affected by this permit. This permit will supercede any conditions of the previous permits that affect the EUs incorporated into this permit.

List of Affected Air Quality Permits and Determinations

74-171-C	98-172-AD
93-076-O	98-172-AD (M-5)
93-101-O	98-228-O
95-506-O (M-1)	98-229-O
96-402-O-(M-1)	98-264-O
96-450-O	98-265-O
97-523-C	

Emission statements are not exactly conclusive in presentation; yet they represent the approximate quantification(s). As technology developed through the timeframe as provided, actual and potential emissions became to be dependent on updating emission factors in the absence of continuous monitoring systems. Historical emission estimates are not conclusive, or exact, yet are an estimate based on the attempt to quantify changes associated with modifications occurring within a time-frame as indicated to reflect upon the net emissions potential decreases established by NSPS, NSR, and BACT applications.

Emissions from the East Flare

The table below details the emissions for the east flare prior to the 1976 reconstruction, after the reconstruction, and after the PSD/BACT review.

	TPY NO_x	TPY CO	TPY PM₁₀	TPY SO₂	TPY VOC
PTE Pre-reconstruction¹	30.1	163.6	4.2	559.0	61.9
PTE Post-reconstruction²	8.0	43.8	1.1	149.5	16.6
Change in PTE	-22.1	-119.8	-3.1	-409.5	-45.3
PTE Post-NSPS Review³	8.0	43.8	1.1	4.0	16.6

- ¹ Potential emissions before 1976 are based on 139,000 lb/hr flare operating at 12% capacity, a molecular weight (MW) of 50.2, a heat rating of 800 BTU/SCF, a H₂S content of 0.6%, and AP-42 (1/95), Section 13.5 except for PM₁₀ emissions. PM₁₀ emissions were based on the calculated heat rating of the flare and AP-42 (7/98), Section 1.4.
- ² Potential emissions after 1976 are based on a 27 MMBTU/hr flare operating at 100% capacity 8,760 hours per year, an H₂S content of 0.6% H₂S, and AP-42 (1/95), Section 13.5.
- ³ Potential emissions after NSPS review are based on a 27 MMBTU/hr flare operating at 100% capacity 8,760 hours per year with a maximum sulfur content of 159 ppm H₂S (NSPS, Subpart J limitation) and AP-42 (1/95), Section 13.5.

Emissions from the Reformer CCR

The table below details the emissions for the Reformer CCR as authorized by Permit No. 98-265-O.

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
0.83	3.65	0.12	0.54	0.39	1.73	0.47	2.04	0.03	0.14

Emissions are based on a coke-burning rate of 49 lbs/hr, which is equivalent to a maximum catalyst recirculation rate of 700 lb/hr and a coke generation rate of 7% of the catalyst weight, with a coke maximum sulfur content of 0.5% by weight. Coke combustion emissions were based on AP-42 (1/95), Section 1.1, for sub-bituminous coal combustion. PM₁₀ emissions also include a recovery factor for the catalyst of 99.99%. The following factors were selected for emission estimates since there are no factors for coke combustion.

NO_x - 34 lb/ton of coke combusted (Pulverized coal fired, wet bottom);

CO - 5 lb/ton of coke combusted (Spreader Stoker);

PM₁₀ - 13.2 lb/ton of coke combusted (Spreader Stoker) & 0.07 lb/hr catalyst;

SO₂ - 38 x (Sulfur Content) lb/ton of coke combusted (Spreader Stoker);

VOC - 1.3 lb/ton of coke combusted (Underfeed Stoker).

Ethylene dichloride (C₂H₄Cl₂) is injected into the Reformer and is discharged as HCl. Ethylene dichloride is almost completely destroyed by reaction with the catalyst and air. Permit No. 98-265-O also limited emissions of hydrogen chloride (HCl) (1.49 lb/hr) and usage of ethylene dichloride in the Reformer (17.2 TPY). If all of the chloride were converted to hydrogen chloride, this would result in approximately 2.89 lb/hr of hydrogen chloride or approximately twice the amount of the HCl emission limit of 1.49 lb/hr. The error in the material usage limit was due to calculations that estimated only one mole of chloride was generated per mole of ethylene dichloride. The usage of ethylene dichloride should have been limited to approximately 8.87 TPY. This permit will correct the material usage limit to a limit that is equivalent to the estimated emissions. Emissions of HCl were originally based on test results which showed that the HCl flow from the Reformer CCR was 0.2% the total flow and a 50% safety factor. The flow of the Reformer was originally estimated at 200 ACFM at a temperature of 800 °F (~5,214 SCFH) to give a flow of 13.72 lb-moles/hr.

Emissions from the FCCU Operation as Constructed and Modified

The table below shows the emissions prior the 1981 FCCU construction, after the construction, subsequent changes in emission after the modification, and after the PSD/BACT review. The 1981 refurbishment basically incorporated the construction of a completely new FCCU. A few of the vessels from the existing FCCU were converted to catalyst storage vessels. The ability to process FCCU feedstock was increased from 20,000 bbl/day to 25,000 bbl/day.

Estimated associated emission increases for the FCCU following the 1981 construction activities are provided along with the post-PSD review emissions. The incremental coke burning capability increased to approximately 19,000 lbs/hr due to the ability to vary the assay characterization of crude feedstocks. Based on a current day analysis of coke production, the FCCU processes approximately 18,000 lbs of coke per hour at a feed-rate of 27,000 bbl/day. Pre-PSD review potential emissions changes are presented as a total, which includes all emission changes since 1974. The emissions for the FCCU following the 1981 construction are based on

an increase of the feed to the FCCU from 25,000 bbl/day to 27,550 bbl/day and the subsequent modification, which increased the throughput to 30,000 bbl/day.

	TPY NO _x	TPY CO	TPY PM ₁₀	TPY SO ₂
PTE Pre-mod.^{1, 2}	363.0	43.5	147.5	309.5
PTE Post-mod.^{3, 4} (25,000 bbl/day)	571.7	556.4	284.4	627.6
Change in PTE	208.7	512.9	136.9	318.1
Pre-PSD Review Changes				
PTE & Ass. Increases ^{5, 4} (27,550 bbl/day)	711.1	603.7	312.5	822.9
PTE & Ass. Increases ^{6, 4} (30,000 bbl/day)	761.0	649.2	339.6	892.7
Cumulative Change in PTE	398.0	605.7	192.1	583.2
PTE Post-PSD Review⁷	442.5	92.0	50.0	217.8

- 1 Emissions are based on a 20,000 bbl/day FCCU feed rate with a sulfur content of 0.2% by weight, and material and energy balances from a process design dated July 16, 1973 and the factors shown below. The FCCU regenerator was a complete burn regenerator that reduced CO emissions from the regenerator to what an incinerator would provide. The design specification for the 1974 permit was a coke burn rate of 11,000 lbs/hr and 8,520 hours of operation per year.
 NO_x - Factor Information Retrieval (FIRE) emission factor for coke burning of 14.0 lbs/ton of coke burned;
 CO - FIRE emissions factor for coke burning of 0.6 lbs/ton of coke burned;
 PM₁₀ - taken directly from the application for Permit No. 74-171-C.
 SO₂ - 6.24 lbs/1,000 lbs of coke burned;
- 2 Emissions from heater H-201 (83.8 MMBTU/hr) are based on a HHV of 1,000 BTU/SCF and the following:
 NO_x - AP-42, Section 1.4 (7/98);
 CO - AP-42, Section 1.4 (7/98);
 PM₁₀ - AP-42, Section 1.4 (7/98);
 SO₂ - A fuel-gas H₂S concentration of 159 ppmv.
- 3 Emissions from the FCCU are based on a 25,000 bbl/day FCCU feed rate with a sulfur content of 0.3% by weight, a coke burn rate of 13,750 lbs/hr and the following factors:
 NO_x - FIRE emission factor for coke burning of 14.0 lbs/ton of coke burned;
 CO - NSPS, Subpart J allowable of 500 ppmv and an estimated flow rate of 47,835 SCFM;
 PM₁₀ - FIRE emission factor for FCCU operations of 242 lbs of PM per 1,000 bbl of feed corrected for an estimated 75% control efficiency for operation of the tertiary cyclones;
 SO₂ - 9.8 lbs/1,000 lbs of coke burned.
- 4 Emissions from heaters H-201 (105 MMBTU/hr), H-252 (60 MMBTU/hr) and H-253 (75 MMBTU/hr) and incinerator H-251 (15 MMBTU/hr) are based on a HHV of 800 BTU/SCF and the following:
 NO_x - AP-42, Section 1.4 (7/98); H-201 - 190 lb/MMSCF, H-252, H-253, and H-251 - 100 lb/MMSCF;
 CO - AP-42, Section 1.4 (7/98);
 PM₁₀ - AP-42, Section 1.4 (7/98);
 SO₂ - A fuel-gas H₂S concentration of 159 ppmv.

- 5 Emissions from the FCCU are based on an increase of the FCCU feed rate to 27,550 bbl/day with a sulfur content of 0.3% by weight, a coke burn rate of 18,229 lbs/hr and the following factors:
NO_x - FIRE emission factor for coke burning of 14.0 lbs/ton of coke burned;
CO - NSPS, Subpart J allowable of 500 ppm_{dv} and an estimated flow rate of 52,714 SCFM;
PM₁₀ - FIRE emission factor for FCCU operations of 242 lbs/1,000 bbl of feed corrected for an estimated 75% control efficiency for operation of the tertiary cyclones;
SO₂ - 9.8 lbs/1,000 lbs of coke burned.
- 6 Emissions from the FCCU are based on an increase of the FCCU feed rate to 30,000 bbl/day with a sulfur content of 0.3% by weight, a coke burn rate of 19,926 lbs/hr and the following factors:
NO_x - FIRE emission factor for coke burning of 14.0 lbs/ton of coke burned;
CO - NSPS, Subpart J allowable of 500 ppm_{dv} and an estimated flow rate of 57,402 SCFM;
PM₁₀ - FIRE emission factor for FCCU operations of 242 lbs/1,000 bbl of feed corrected for an estimated 75% control efficiency for operation of the tertiary cyclones.
SO₂ - 9.8 lbs/1,000 lbs coke burned;
- 7 Proposed and accepted BACT Emissions for the FCCU:
NO_x Emissions:
Hydrotreatment of the FCCU feedstock and LNB in the CO boiler was proposed, and accepted, as BACT. The BACT emission limit for the FCCU regenerators is 356.8 TPY. To meet this standard, in addition to hydrotreatment of the feedstock, provided with variable assays of crude oil feedstock to the refinery, it will first be necessary to minimize NO_x formation by excess air monitoring and control. If the emissions standard cannot be achieved, it will then be necessary to install additional NO_x controls on the FCCU flue gas stream. Air preheaters H-252 and H-253 are vented through the FCCU and emissions are incorporated into the BACT limit.
The federally enforceable emission limit requested for H-201 the FCCU Feedstock preheater is 85.7 TPY (149 lb/MMSCF @ 800 BTU/SCF).
CO Emissions:
Use of a CO Boiler/Incinerator for the FCCU No. 1 Regenerator and high temperature regeneration for the FCCU No. 2 Regenerator was proposed, and accepted, as BACT. The BACT emission limit for the FCCU regenerators is 54.1 TPY. H-252 and H-253 are vented through the FCCU and emissions are incorporated into the BACT limit.
CO emissions for H-201 are estimated at 37.9 TPY using AP-42, Section 1.4 (7/98).
PM₁₀ Emissions:
Installation of a WS to control PM₁₀ emissions from the FCCU regenerators was proposed, and accepted, as BACT. The BACT emission limit for the FCCU regenerators is 46.6 TPY. H-252 and H-253 are vented through the FCCU and emissions are incorporated into the BACT limit.
PM₁₀ emissions for H-201 are estimated at 3.4 TPY using AP-42, Section 1.4 (7/98).
SO₂ Emissions:
Installation of a WS to control SO₂ emissions from the FCCU regenerators was proposed, and accepted, as BACT. The BACT emission limit for the FCCU regenerators is 202.4 TPY. The emissions were evaluated using a feedstock sulfur concentration of 0.3% by weight. The weight % sulfur in FCCU feed can be greater than 0.3% after installation of the scrubber; however, SO₂ emissions from the scrubber shall not exceed the limit of 193 TPY. This can be achieved by increasing the scrubber performance when necessary if the weight % sulfur in the FCCU feed is above 0.30%. H-252 and H-253 are vented through the FCCU and emissions are incorporated into the BACT limit.
SO₂ emissions for H-201 are estimated at 15.44 TPY using the NSPS, Subpart J, allowable of 159 ppm_v.

Emissions from the FCCU as Evaluated in the BACT Submittal

The table below shows the emissions as they were evaluated in the proposed and accepted BACT submittal. The baseline emissions and the proposed BACT limits do not include the FCCU feedstock preheater.

	TPY NO_x	TPY CO	TPY PM₁₀	TPY SO₂
Baseline Emissions¹	473.1	229.1	466.4	2,024.7
BACT Emission Limits²	356.8	54.1	46.6	202.4
Emission Reductions	116.3	175.0	419.8	1,822.3

¹ Baseline emissions for the FCCU are based on the following:

NO_x Emissions:

NO_x emissions from the FCCU No. 1 Regenerator were based on stack test results (65.34 lb/hr), which was conducted on January 22-23, 1998, extrapolated from a feedstock rate of 25,836 bbl/day to 30,000 bbl/day. NO_x emissions from the FCCU No. 2 Regenerator were based on stack test results (27.69 lb/hr), which was conducted on January 22-23, 1998, extrapolated from a feedstock rate of 25,836 bbl/day to 30,000 bbl/day.

CO Emissions:

CO emissions from the FCCU No. 1 Regenerator were based on an average of stack test results (89.28, 16.96, 26.49 lb/hr), which were conducted on January 22-23, 1998, August 9, 1999, and August 12, 1999, extrapolated from feedstock rates of 25,836, and 22,050, 26,322 bbl/day, respectively, to 30,000 bbl/day. CO emissions from the FCCU No. 2 Regenerator were based on the detection limit for CO from stack test results conducted on January 22-23, 1998.

PM₁₀ Emissions:

PM₁₀ emissions from the FCCU No. 1 Regenerator were based on stack test results (52.56r), which was conducted on August 12 1999, extrapolated from a feedstock rate of 26,322 bbl/day to 30,000 bbl/day. PM₁₀ emissions from the FCCU No. 2 Regenerator were based on stack test results (40.87 lb/hr), which was conducted on August 12, 1999, extrapolated from a feedstock rate of 26,322 bbl/day to 30,000 bbl/day.

SO₂ Emissions:

SO₂ emissions from the FCCU No. 1 Regenerator were based on stack test results (246.18 lb/hr), which was conducted on January 22-23, 1998, extrapolated from a feedstock rate of 25,836 bbl/day and a feedstock sulfur content of 0.2733% by weight to 30,000 bbl/day and a feedstock sulfur content of 0.3% by weight. NO_x emissions from the FCCU No. 2 Regenerator were based on stack test results (112.35 lb/hr), which was conducted on August 12, 1999, extrapolated from a feedstock rate of 26,322 bbl/day and a feedstock sulfur content of 0.2587% by weight to 30,000 bbl/day and a feedstock sulfur content of 0.3% by weight.

² BACT emission limits for the FCCU are based on the following:

NO_x Emissions:

NO_x emissions from the FCCU No. 1 Regenerator were based on a 35% reduction of baseline emissions. NO_x emissions from the FCCU No. 2 Regenerator were based on the baseline emission estimates.

CO Emissions:

CO emissions from the FCCU No. 1 Regenerator were based on a 78% reduction of baseline emissions. CO emissions from the FCCU No. 2 Regenerator were based on 99% reduction of the NSPS baseline emissions, which are based on a limit of 500 ppmv a flow rate of 47,712 SCFM, and a moisture content of 8.5%.

PM₁₀ Emissions:

PM₁₀ emissions from the FCCU No. 1 and No. 2 Regenerators were based on a 90% reduction of baseline emissions (front-half).

SO₂ Emissions:

SO₂ emissions from the FCCU No. 1 and No. 2 Regenerators were based on a 90% reduction of baseline emissions.

Emissions from the FCCU After Application of CO Boiler SEP

The table below shows the emissions as the emissions from the FCCU after application of the proposed and accepted supplemental environmental project of replacing the existing FCCU No. 1 Regenerator CO Boiler/Incinerator with a larger CO Boiler that would be able to handle the total flow of the FCCU No. 1 Regenerator. The existing CO Boiler will still be equipped with BACT and will be maintained in standby or limited supplemental service. The existing Incinerator will be removed from service.

	TPY NO _x	TPY CO	TPY PM ₁₀	TPY SO ₂
BACT Emission Limits	356.8	54.1	46.6	202.4
SEP Emission Estimates¹	179.9	54.1	46.6	202.4
Emission Reductions	176.9	0.0	0.0	0.0

- ¹ SEP emissions estimates remain the same as the BACT emission limits for the FCCU except for NO_x emission which are based on the following:

NO_x Emissions:

NO_x emissions from the FCCU No. 1 Regenerator were based are based on an 81.9% reduction of BACT emission limits. NO_x emissions from the FCCU No. 2 Regenerator are based on the baseline or BACT emission limits.

PM Emissions from the Catalyst Hoppers

The table below summarizes PM emissions prior to the 1981 modification of the catalyst hopper system for the FCCU, after the modification, subsequent modifications, and after the PSD BACT review. A PM₁₀ emission limitation of 2 TPY was requested for the Catalyst Hoppers so that the emission limitation would be consistent with the proposed BACT.

	TPY PM	TPY PM ₁₀
PTE Pre-Construction¹	61.3	24.5
PTE Post-Construction²	98.8	40.2
Change in PTE	37.5	15.7
Pre-BACT PTE³	29.6	20.1
Post-PSD/BACT PTE⁴	2.0	2.0

- ¹ Potential emissions before 1981 are based on a continuous catalyst recirculation rate of approximately 1,400,000 lbs/hr through two hoppers at a FCCU processing rate of 20,000 bbl/day. Emissions are estimated utilizing an emission factor of 0.01 lbs PM/ton (AP-42, Section 11.24 (1/95), Table 11.24.2, high moisture ore, material handling and transfer - all minerals except bauxite) and continuous

- operation. PM₁₀ emissions are 40% of PM emissions. The high moisture ore factor was utilized since live steam is injected to control emissions of PM.
- 2 Potential emissions after 1981 are based on a continuous catalyst recirculation rate of approximately 2,100,000 lbs/hr through two spent catalyst hoppers and the emission factor above in ⁽¹⁾; a fresh catalyst hopper with a maximum transfer rate of approximately 13 tons/hr, an emission factor of 0.12 lbs PM/ton (AP-42, Section 11.24 (1/95), Table 11.24.2, low moisture ore, material handling and transfer - all minerals except bauxite), and continuous operation. PM₁₀ emissions for the low moisture ore are 50% of PM emissions.
 - 3 Potential emissions were based on the information in ⁽²⁾ and installation of cyclones to control emissions. The control efficiency of the cyclones was assessed as a minimum of 70% for PM and 50% for PM₁₀.
 - 4 Potential emissions estimates include the existing operation of cyclones with steam-injection in conjunction with the WS to be installed to control PM. PM is assessed to be the same as PM₁₀ at the WS outlet.

Emissions from Operation of the CO Boiler

The CO boiler was rated 92 MMBTUH by Zurn Industries based on a design performance summary sheet dated September 7, 1984. The primary design basis was for the boiler was firing 110,000 lb/hr of the #1 regenerator's off-gas and 1,700 lb/hr of refinery fuel-gas. The secondary design basis was firing 0.1283 MMSCF of refinery fuel-gas. The table below summarizes emissions for criteria pollutants for the CO boiler operation. The emissions shown below only represent the emissions arising from operation of the boiler itself and not the criteria pollutant emissions processed through the boiler.

	TPY NO _x	TPY CO	TPY SO ₂	TPY PM ₁₀
PTE Pre-PSD¹	40.0	33.0	13.4	3.0
Post-PSD/BACT PTE²	12.1	33.0	13.4	3.0

- 1 Emissions are based on a heat input rating of 92 MMBTU/hr, a HHV of 800 BTU/SCF, and the following factors:
 NO_x - AP-42, Section 1.4 (7/98);
 CO - AP-42, Section 1.4 (7/98);
 PM₁₀ - AP-42, Section 1.4 (7/98);
 SO₂ - A fuel-gas H₂S concentration of 159 ppmv and a firing rate of 0.1283 MMSCF/hr of refinery fuel gas.
- 2 All emissions remained the same except for NO_x emissions, which are now based on factors for LNB (~ 0.03 lb/MMSCF).

Emissions from Heater H-411

The table below details the emissions for heater H-411.

	NO _x		CO		PM ₁₀		SO ₂		VOC	
Heater	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
H-411	2.75	12.02	2.31	10.10	0.21	0.91	0.94	4.11	0.15	0.66

Emissions are based on continuous operation, a maximum heat input of 28.0 MMBTUH a HHV of 800 BTU/SCF, and the following factors:
 NO_x - AP-42, Section 1.4 (7/98);
 CO - AP-42, Section 1.4 (7/98);

PM₁₀ - AP-42, Section 1.4 (7/98);
 SO₂ - A fuel-gas H₂S concentration of 159 ppmv
 VOC - AP-42, Section 1.4 (7/98);

Fugitive Emissions for the NHT (Area 400), Platformer (Area 400), and Isom (Area 450)

The table below summarizes emissions for the NHT, Platformer, and Isom units fugitive equipment leaks prior to the 1987 modification, after the modifications, and after the PSD BACT review and application of a leak detection and repair (LDAR) program.

	TPY VOC
PTE Pre-Mod.¹	339.0
PTE Post-Mod.²	396.0
Change in PTE	57.0
Post-PSD/BACT PTE³	78.8

- ¹ Potential emissions before 1987 are based on equipment installed before 1987 and the average refinery emission factors with no LDAR program. Controls are represented for the PRV(s) and compressors. PRV(s) emissions are controlled with a flare with a 95% control efficiency and the compressors are equipped with tandem-seals.
- ² Potential emissions after the 1987 modification are based on current equipment counts and the average refinery emission factors with no LDAR program. Controls are represented for the PRV(s) and compressors. PRV(s) emissions are controlled with a flare with a 95% control efficiency and the compressors are equipped with tandem-seals.
- ³ Post-PSD/BACT review potential emissions are based on present day equipment counts evaluated at LDAR screening values of a maximum 10,000-ppm as provided for in NSPS, Subpart GGG. Potential emissions include a 95% destruction efficiency for PRV(s) that are routed to the flares and Tandem-seal compressor arrangements.

Emissions from the Crude Unit Indirect-Fired Heat Exchangers H-102A & H-102B

Provided below is a summary of the emissions of criteria pollutants for H-102A and H-102B prior to the 1990 modification, after the 1990 modification, and after the PSD BACT review.

	TPY NO _x	TPY CO	TPY PM ₁₀	TPY SO ₂	TPY VOC
PTE Pre-mod.¹					
H-102A	120.2	36.1	3.3	14.7	2.4
H-102B	27.1	22.7	2.1	9.3	1.5
Sub-Total	147.3	58.8	5.4	24.0	3.9
PTE Post-mod.²					
H-102A	118.3	52.3	4.7	21.3	3.4
H-102B	110.1	48.7	4.4	19.8	3.2
Sub-Total	228.4	101.0	9.1	41.1	6.6
Change in PTE	81.1	42.2	3.7	17.1	2.7

	TPY NO _x	TPY CO	TPY PM ₁₀	TPY SO ₂	TPY VOC
Post-PSD/BACT PTE³					
H-102A	28.6	52.3	7.7	21.3	3.4
H-102B	34.9	48.7	7.2	19.8	3.2
Sub-Total	63.5	101.0	14.9	41.1	6.6

- 1 Emissions are based on a HHV of 800 BTU/SCF, a heat input rating of 100 and 63 MMBTU/hr for heaters H-102A & H-102B, respectively, and the following:
 NO_x - AP-42, Section 1.4 (7/98);
 CO - AP-42, Section 1.4 (7/98);
 PM₁₀ - AP-42, Section 1.4 (7/98);
 SO₂ - A fuel-gas H₂S concentration of 159 ppmv;
 VOC - AP-42, Section 1.4 (7/98).
- 2 Emissions are based on a HHV of 800 BTU/SCF, a heat input rating of 145 and 135 MMBTU/hr for heaters H-102A & H-102B, respectively, and the following:
 NO_x - AP-42, Section 1.4 (7/98);
 CO - AP-42, Section 1.4 (7/98);
 PM₁₀ - AP-42, Section 1.4 (7/98);
 SO₂ - A fuel-gas H₂S concentration of 159 ppmv;
 VOC - AP-42, Section 1.4 (7/98).
- 3 Emissions are based on a HHV of 800 BTU/SCF, a heat input rating of 145 and 135 MMBTU/hr for heaters H-102A & H-102B, respectively, and the following:
 NO_x - BACT determinations and ultra-low NO_x burners;
 CO - AP-42, Section 1.4 (7/98);
 PM₁₀ - 1.28 times AP-42, Section 1.4 (7/98);
 SO₂ - A fuel-gas H₂S concentration of 159 ppmv;
 VOC - AP-42, Section 1.4 (7/98).

Crude Unit Area Fugitive Equipment Leaks

The table below summarizes emissions for the crude unit area fugitive equipment leaks prior to the 1990 modification, after the modification, and after the PSD BACT review and application of a LDAR program.

	TPY VOC
PTE Pre-mod.¹	771.0
PTE Post-mod.²	1,166.8
Change in PTE	395.8
Post-PSD/BACT PTE³	261.3

- 1 Potential emissions before 1990 were assessed utilizing a production ratio of the base year 1974 (60,000 bbl/day established in the application for Permit No. 74-171) to the present day pre-PSD review production capability (85,000 bbl/day) assuming that equipment counts are proportionally related to throughput.
- 2 Pre-PSD review potential emissions were based on present day equipment counts evaluated at the average refinery emission factors.

- 3 Post-PSD review potential emissions are based on present day equipment counts evaluated at LDAR screening values of a maximum 10,000 ppm as provided for in Title 40 CFR Part 60, Subpart GGG. This is equivalent to an overall control efficiency for valves of approximately 62 to 70% from the average refinery emissions factors.

Crude Unit Area Wastewater Treatment System Fugitive Equipment Leaks

The table below summarizes emissions for the crude unit area wastewater treatment fugitive equipment leaks prior to the 1990 modification, after the modification, and after the PSD BACT review and application of a LDAR program.

	TPY VOC
PTE Pre-mod.¹	16.9
PTE Post-mod.²	23.9
Change in PTE	7.0
Post-PSD/BACT PTE³	23.9

- 1 Based on pre-modification processing rate of 60,000 bbl/day of crude oil.
- 2 Based on a processing rate of 85,000 bbl/day processing-rate.
- 3 Implementation of Title 40 CFR Part 60, Subpart QQQ, reduces emissions to a certain degree, but the extent is minute compared the end-of-line release from aerated biological reactors. The effectiveness of Subpart QQQ provides a greater reduction of VOC emissions when implemented in conjunction with Title 40 CFR Part 61, Subpart FF.

Fugitive Emissions for the Alkylation Unit

The table below summarizes emissions for the alkylation unit fugitive equipment leaks prior to the 1991 modification, after the modifications, and after the PSD BACT review and application of LDAR.

	TPY VOC
PTE Pre-Mod.¹	145.7
PTE Post-Mod.²	363.9
Change in PTE	218.2
Post-PSD/BACT PTE³	92.8

- 1 Potential emissions prior to 1991 are based on equipment installed before 1991 and the average refinery emission factors with no LDAR program. PRV(s) emissions are controlled with a flare.
- 2 Potential emissions after the 1991 modification are based on current equipment counts and the average refinery emission factors with no LDAR program. PRV(s) are vented to a flare which achieves a 95% destruction efficiency for VOC.
- 3 Post-PSD/BACT review potential emissions are based on present day equipment counts evaluated at LDAR screening values of a maximum 10,000-ppm as provided for in NSPS, Subpart GGG. Potential emissions include a 95% destruction efficiency for PRV(s) that are routed to the flares.

Emissions for the West Flare

The table below details the emissions for the west flare prior to reconstruction and after the PSD/BACT review.

	TPY NO _x	TPY CO	TPY PM ₁₀	TPY SO ₂	TPY VOC
PTE Pre-mod.¹	25.6	139.4	2.9	381.2	52.8
Current PTE ²	8.3	45.4	1.2	4.1	17.7
Change in PTE	-17.3	-94.0	-1.7	-377.1	-35.1

¹ Potential emissions before 1976 are based on 150,000 lb/hr flare operating at 12% capacity, a MW of 79.5, a heat rating of 800 BTU/SCF, a H₂S content of 0.6%, and AP-42, Section 13.5 (1/95) except for PM₁₀ emissions. PM₁₀ emissions were based on the calculated heat rating of the flare and AP-42, Section 1.4 (7/98).

² Potential emissions after NSPS review are based on 28 MMBTU/hr flare operating at 100% capacity 8,760 hours per year with a maximum sulfur content of 159 ppm H₂S and AP-42, Section 13.5 (1/95).
Note: removal of streams vented to the flare enabled reductions in the maximum capacity of the flare.

Emissions for Reforming Heater H-15001

The table below shows the emissions for heater H-15001 as authorized by Permit No. 95-506-O (M-1).

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
10.85	47.53	8.80	38.54	1.32	5.78	3.80	16.63	0.80	3.51

Emissions for the permit were based on continuous operation and the emission factors shown below:

NO_x – 0.037 lb/MMBTU;
CO – 0.030 lb/MMBTU;
PM₁₀ – 0.0045 lb/MMBTU;
SO₂ – 0.01295 lb/MMBTU;
VOC – 0.00274 lb/MMBTU.

In the next table, emissions of SO₂, PM₁₀, and VOC for heater H-15001 have been updated to reflect the current AP-42, Section 1.4 (7/98) emission factors which are believed to be more representative of the emissions from the heater.

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
10.85	47.53	8.80	38.54	2.19	9.57	9.83	43.04	1.58	6.93

The corrected emissions are based on continuous operation and the emission factors shown below:

PM₁₀ - AP-42, Section 1.4 (7/98);
SO₂ - A fuel-gas H₂S concentration of 159 ppmv;
VOC - AP-42, Section 1.4 (7/98).

Fugitive Emissions for the Amine Unit

The table below summarizes emissions changes for the Amine Unit prior to the 1993 modification, after the 1993 modification, and after the PSD/BACT review.

	TPY VOC	TPY H₂S⁴	TPY SO₂⁴
PTE Pre-Mod.¹	27.0	5.1	---
PTE Post-Mod.²	78.1	14.7	3.8
Change in PTE	51.1	9.6	3.8
Post-PSD/BACT PTE³	13.2	2.5	3.8

- ¹ Potential emissions before 1993 are based on fugitive equipment after the 1974 construction activities and includes the existing system and the equipment installed per the Post-1974 construction and the average refinery emission factors with no LDAR program.
- ² Potential emissions after the 1993 modifications are based on current equipment counts and the average refinery emission factors with no LDAR program and no venting of PRVs to flares.
- ³ Post-PSD review potential emissions are based on present day equipment counts evaluated at LDAR screening values of a maximum 10,000-ppm as provided for in NSPS, Subpart GGG. Potential emissions include a 95% destruction efficiency for PRV(s) routed to flares.
- ⁴ Emissions of H₂S are based on an overall unit wide concentration of 24,000 ppm of vented emissions not routed to a flare. SO₂ emissions are based on the venting of a 24,000 ppm H₂S vapor PRV to the flare.

Fugitive Emissions for the Saturated Gas Plant Unit

The table below summarizes emissions for the saturated gas plant fugitive equipment leaks prior to construction in 1993, after the construction, of modifications after the 1993 construction, and after the PSD BACT review.

	TPY VOC
PTE Pre-Construction¹	156.7
PTE Post-Construction²	178.1
Pre-BACT PTE³	251.3
Change in PTE	94.6
Post-PSD/BACT PTE⁴	107.9

- ¹ Potential emissions before 1993 are based on equipment installed as of Permit No. 74-171-O and the average refinery emission factors with no LDAR program.
- ² Potential emissions after 1993 are based on the pre-construction emissions plus the emissions change due to the addition of the LPG amine contactor as authorized under Permit No. 93-076-C/O.
- ³ Potential emissions after the 1993 construction and subsequent modifications are based on current equipment counts and the average refinery emission factors with no LDAR program.

- 4 Post-PSD review potential emissions are based on present day equipment counts evaluated at LDAR screening values of a maximum 10,000-ppm as provided for in NSPS, Subpart GGG. Potential emissions include a 95% destruction efficiency for 13 PRV(s) routed to flares; whereas the remainder are atmospherically vented.

Emissions for the Diesel-Fired Emergency Air Compressor C-80018

The table below details the emissions for the 400-hp Cummings diesel-fired emergency air compressor as authorized by Permit No. 98-229-O and updated to reflect current operations.

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
12.40	24.80	2.67	5.34	0.88	1.76	0.14	0.28	1.01	2.01

Emissions are based on 4,000 hours of operation per year a rating of 400-hp and the following factors:

NO_x - AP-42, Section 3.3, (10/96);

CO - AP-42, Section 3.3, (10/96);

PM₁₀ - AP-42, Section 3.3, (10/96);

SO₂ - AP-42, Section 3.4, (10/96) and a maximum sulfur content of 0.05% by weight;

VOC - AP-42, Section 3.3, (10/96).

Emissions from the No. 2 Sour Water Stripper Feed Storage Tank T-83001

The table below summarizes emissions from the No. 2 sour water stripper storage tank as authorized by Permit No. 95-506-O (M-1). The emissions result from the barrier fluid, which is diesel-fuel. Emissions are based on a throughput value of 2,565,500 bbl/yr. Operation of the tank requires a barrier of diesel fluid at all times. The emissions were then updated to reflect the maximum filling rate of 205 gallons per minute (gpm) and the site specific maximum vapor pressure of the diesel fuel the the heated tank of 0.105 psia. The increase in emissions does not change the determinations in Permit No. 95-506-O (M-1).

	VOC	
	lb/hr	TPY
Permitted Emissions	0.18	0.87
Updated Emissions	4.0	6.20

Fugitive Emissions for the Olefin Treating Unit

The table below summarizes emissions for the olefin treating unit fugitive equipment leaks prior to the 1994 modification, after the modifications, and after the PSD BACT review.

	TPY VOC
PTE Pre-Mod.¹	126.0
PTE Post-Mod.²	212.0
Change in PTE	86.0
Post-PSD/BACT PTE³	31.2

- 1 Potential emissions before 1994 are based on equipment installed before 1994 and the average refinery emission factors with differentiation of valve services and no LDAR program.
- 2 Potential emissions after the 1994 modification are based on current equipment counts and the average refinery emission factors with differentiation of valve services and no LDAR program.
- 3 Post-PSD/BACT review potential emissions are based on present day equipment counts evaluated at LDAR screening values of a maximum 10,000-ppm as provided for in NSPS, Subpart GGG.

Emissions for Blowstill Incinerator HI-801

The table below details the emissions for the blowstill incinerator as authorized by Permit No. 95-506-O (M-1).

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
35.09	153.7	0.61	2.68	0.01	0.38	205.5	899.9	0.05	0.21

Emissions for Permit No. 95-506-O (M-1) were based on the following:

NO_x - For emissions from combustion of the auxiliary fuel, emissions were based on a heat rating of 15 MMBTUH, a heat content of 859 BTU/SCF, and AP-42, Section 1.4 (1/95); For emissions from combustion of the oil carryover, emissions were based on 4,099 lb/hr of oil carried over into the blowstill incinerator, an estimated weight of 8.534 lb/gallon, and an emission factor of 67.97 lb/1000 gal based on a nitrogen content of 0.339% [$\text{lb}/1000 \text{ gal} = 22 + 400(\text{N})^2$];

CO - CO emissions were only based on combustion of the auxiliary fuel and AP-42, Section 1.4 (1/95) and did not include combustion of the waste gas;

PM₁₀ - PM₁₀ emissions were only based on combustion of the auxiliary fuel and AP-42, Section 1.4 (1/95), and did not include combustion of the waste gas;

SO₂ - For emissions from the combustion of the auxiliary fuel, emissions were based on a heat rating of 15 MMBTUH, a heat content of 859 BTU/SCF, a fuel-gas H₂S concentration of 159 ppmv, and AP-42, Section 1.4 (1/95); For emissions from combustion of the oil carryover, emissions were based on 4,099 lb/hr of oil carried over into the blowstill incinerator, an estimated weight of 8.534 lb/gallon, and a sulfur content of 2.5%;

VOC - VOC emissions were only based on combustion of the auxiliary fuel and AP-42, Section 1.4 (1/95), and did not include combustion of the waste gas.

The emissions from this unit have been updated to be representative of the current emission levels, corrected for emissions that were not included in the original calculations, and as modified by Applicability Determination No. 98-172-AD. Applicability Determination No. 98-172-AD evaluated installation of a scrubber for the waste gases combusted in the incinerator to reduce SO₂ emissions to levels associated with the NSPS, Subpart J requirements for fuel gas combustion devices. The table below shows the new emission estimates for the Blowstill Incinerator.

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
9.36	41.03	23.05	101.0	0.46	2.03	7.98	34.94	8.72	38.20

Emissions are based on the following:

NO_x - For emissions from combustion of the auxiliary fuel, emissions were based on a heat rating of 12 MMBTUH, a heat content of 750 BTU/SCF, and the emission factor from AP-42, Section 1.4 (7/98) multiplied by 1.5; For emissions from combustion of the waste gas, emissions were based on a

flow rate of 21,287 lb/hr of waste gas, a heat content of 2,363 BTU/lb, and the emission factor from AP-42, Section 1.4 (7/98) multiplied by 1.5; For emissions from nitrogen in the waste gas (as NO₂), emissions were based on a concentration of 6.2 ppmv and a flow rate of 276,294 SCFH.

CO - For emissions from combustion of the auxiliary fuel, emissions were based on a heat rating of 12 MMBTUH and AP-42, Section 13.5 (1/95); For emissions from combustion of the waste gas, emissions were based on a flow rate of 21,287 lb/hr of waste gas, a heat content of 2,363 BTU/lb, and AP-42, Section 13.5 (1/95);

PM₁₀ - For emissions from combustion of the auxiliary fuel, emissions were based on a heat rating of 12 MMBTUH, a heat content of 750 BTU/SCF, and AP-42, Section 1.4 (7/98); For emissions from combustion of the waste gas, emissions were based on a flow rate of 21,287 lb/hr of waste gas, a MW of 29 lb/lb-mole, a ratio of 379 SCF/lb-mole, and AP-42, Section 1.4 (7/98);

SO₂ - A refinery fuel-gas H₂S concentration of 159 ppmv, a flow rate of 0.015 MMSCFH of auxiliary fuel, and a flow rate of 0.276 MMSCFH of waste gas;

VOC - For emissions from combustion of the auxiliary fuel, emissions were based on a heat rating of 12 MMBTUH and AP-42, Section 13.5 (1/95); For emissions from combustion of the waste gas, emissions were based on a flow rate of 21,287 lb/hr of waste gas, a heat content of 2,363 BTU/lb, and AP-42, Section 13.5 (1/95);

Emissions for the Diesel-Fired Emergency Generators EEQ-8801 & EEQ-80001

The table below details the emissions for the 750-kW Detroit DMT D Model 16V92TA diesel-fired emergency generator (EEQ-8801) as authorized by Permit No. 97-523-O and updated to reflect current operations. Permit No. 97-523-O also authorized the operation of an 80-kW Onan DGDA emergency generator (EEQ-80001) with a Cummins 6BT5.9-G1 diesel engine. Emissions for this engine are also included below. The Permit No. 97-253-O authorized operation of the engines up to 200hours per year. This permit will establish a limit of 800 hours per year.

EEQ	NO _x		CO		PM ₁₀		SO ₂		VOC	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
8801	28.80	11.52	7.65	3.06	0.52	0.21	0.45	0.18	0.74	0.29
80001	9.16	3.66	1.97	0.79	0.64	0.26	0.10	0.04	0.75	0.30

Emissions are based operating 800 hours per year, a maximum fuel input of 461.5 and 106.5 lbs/hr at 19,500 BTU/lb, or 9.00 and 2.08 MMBTUH for generators EEQ-8801 & EEQ-80001, respectively and the following factors:

NO_x - AP-42, Section 3.3 & 3.4, (10/96) for EEQ-8801 & EEQ-80001, respectively;

CO - AP-42, Section 3.3 & 3.4, (10/96) for EEQ-8801 & EEQ-80001, respectively;

PM₁₀ - AP-42, Section 3.3 & 3.4, (10/96) for EEQ-8801 & EEQ-80001, respectively;

SO₂ - AP-42, Section 3.4, (10/96) and a maximum sulfur content of 0.05% by weight;

VOC - AP-42, Section 3.3 & 3.4, (10/96) for EEQ-8801 & EEQ-80001, respectively.

Emissions from the Heaters H-403, H-404, H-405, H-406, H-401A, H-401B, H-402A, H-402B, and H-407, and Boilers B-802, B-802

The table below details the emissions for heaters and boilers listed above.

Heater	NO _x		CO		PM ₁₀		SO ₂		VOC	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
H-403	9.68	42.38	8.13	35.60	0.74	3.22	3.31	14.48	0.53	2.33
H-404	4.71	20.61	3.95	17.31	0.36	1.57	1.61	7.04	0.26	1.13
H-405	4.93	21.60	4.14	18.14	0.37	1.64	1.69	7.38	0.27	1.19
H-406	2.75	12.02	2.31	10.10	0.21	0.91	0.94	4.11	0.15	0.66
H-401A	1.57	6.87	1.32	5.77	0.12	0.52	0.54	2.35	0.09	0.38
H-401B	1.67	7.30	1.40	6.13	0.13	0.55	0.57	2.49	0.09	0.40
H-402A	1.35	5.93	1.14	4.98	0.10	0.45	0.46	2.03	0.07	0.33
H-402B	1.56	6.83	1.31	5.74	0.12	0.52	0.53	2.33	0.09	0.38
H-407	2.45	10.74	2.06	9.02	0.19	0.82	0.84	3.67	0.13	0.59

Boilers	NO _x		CO		PM ₁₀		SO ₂		VOC	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
B-802	7.63	33.41	6.41	28.06	0.58	2.54	2.61	11.42	0.42	1.84
B-803	7.44	32.59	6.25	27.38	0.57	2.48	2.54	11.14	0.41	1.79

Emissions are based on a HHV of 800 BTU/SCF, on the following heat input ratings, and the following factors:

H-403 - 98.7, H-406 - 28.0, H-401A - 16.0, H-401B - 17.0, H-402A - 13.8, H-402B - 15.9, H-407 - 25.0 B-802 - 77.8, - B-803 - 75.9;
 NO_x - AP-42, Section 1.4 (7/98);
 CO - AP-42, Section 1.4 (7/98);
 PM₁₀ - AP-42, Section 1.4 (7/98);
 SO₂ - A fuel-gas H₂S concentration of 159 ppmv;
 VOC - AP-42, Section 1.4 (7/98).

Emissions from the Gasoline and Diesel Loading Dock Vapor Incinerator

The table below quantifies emissions for the vapor incinerator at maximum capacity.

	TPY NO _x	TPY CO	TPY PM ₁₀	TPY SO ₂	TPY VOC
PTE Pre-mod.¹	----	----	----	----	396.0
PTE Post-mod.²	15.8	39.5	<0.01	0.01	73.66
Change in PTE	15.8	39.5	0.0	0.01	-322.3

¹ Emission estimates were based on an average of emissions from 1993, 1995, and 1995, for the loading dock. During this time the facility loaded an average of 2,339,930 bbl/yr of regular unleaded gasoline, 426,207 bbl/yr of premium unleaded gasoline, and 1,173,125 bbl/yr of diesel fuel.

² VOC emissions from the vapor combustor are based on a loading 22,525,714 bbl/yr and 155,782 gal/hr of gasoline and diesel and a limit of 10 mg VOC/L gasoline loaded. Fugitive VOC emissions from loading losses are based on loading loss emission calculations and a collection efficiency of 99.2% for

gasoline. Annual loading losses were based on loading 22,525,714 bbl/yr of gasoline, AP-42 (1/95), Section 5.2, a saturation factor of 1.0, a vapor pressure (vp) of 5.8 psia, a temperature of 60 °F, and a vapor molecular weight of 65. Hourly loading losses were based on loading 155,782 gallons per hour (gph) of gasoline, AP-42 (1/95), Section 5.2, a saturation factor of 1.0, a maximum vp of 9.4 psia, a maximum temperature of 93 °F, and a vapor molecular weight of 65. NO_x, CO, and SO₂ emissions from the vapor combustor are based on the following emission factors:

NO_x – 4 mg/L of gasoline loaded (0.03338 lb/Mgal);
 CO - 10 mg/L of gasoline loaded (0.08345 lb/Mgal);
 SO₂ - Combustion of 2,000 gallons of distillate fuel oil and a factor of 7.1 lb/Mgal.

Emissions from the Hot Oil Heaters H-100024 and H-210001

The table below details the emissions for heaters H-100024 and H-210001 as authorized by Permits No. 98-172-C and 96-402-O (M-1), respectively and updated to reflect current operation. Heater H-100024 is equipped with LNB.

	NO _x		CO		PM ₁₀		SO ₂		VOC	
Heater	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
H-100024	0.68	2.96	1.11	4.87	0.10	0.44	0.45	1.98	0.07	0.32
H-210001	1.20	5.24	1.00	4.40	0.09	0.40	0.01	0.05	0.07	0.29

Emissions are based on a HHV of 800 BTU/SCF, a heat input rating of 13.5 and 12.2 MMBTU/hr for heaters H-100024 & H-210001, respectively, and the following factors:

NO_x - AP-42, Section 1.4 (7/98);
 CO - AP-42, Section 1.4 (7/98);
 PM₁₀ - AP-42, Section 1.4 (7/98);
 SO₂ – For H-100024 - A fuel-gas H₂S concentration of 159 ppmv; For H-210001 - A fuel-gas H₂S concentration of 4 ppmv;
 VOC - AP-42, Section 1.4 (7/98).

Emissions from Fugitive Equipment Leaks Associated with H-100024

The table below summarizes emissions from the fugitive equipment leaks associated with the operation of hot oil heater H-100024 prior to LDAR requirements.

	TPY VOC
PTE Pre-NSPS ¹	8.9
PTE Post-NSPS ²	3.5
Change in PTE	-5.4

¹ Potential emissions before application of NSPS, Subpart GGG are based on equipment installed and no LDAR program.

² Post-NSPS emissions are based on present day equipment counts evaluated at LDAR screening values of a maximum 10,000-ppm as provided for in NSPS, Subpart GGG.

TOTAL POTENTIAL EMISSIONS PRIOR TO MODIFICATIONS

	NO_x		CO		PM₁₀		SO₂		VOC	
EU	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
T-83001	----	----	----	----	----	----	----	----	0.18	0.87
H-102B	25.15	110.1	11.12	48.70	1.01	4.41	4.52	19.81	0.73	3.19
H-102A	27.01	118.3	11.94	52.30	1.08	4.73	4.86	21.28	0.78	3.42
H-403	9.68	42.38	8.13	35.60	0.74	3.22	3.31	14.48	0.53	2.33
H-404	4.71	20.61	3.95	17.31	0.36	1.57	1.61	7.04	0.26	1.13
H-405	4.93	21.60	4.14	18.14	0.37	1.64	1.69	7.38	0.27	1.19
H-406	2.75	12.02	2.31	10.10	0.21	0.91	0.94	4.11	0.15	0.66
H-401A	1.57	6.87	1.32	5.77	0.12	0.52	0.54	2.35	0.09	0.38
H-401B	1.67	7.30	1.40	6.13	0.13	0.55	0.57	2.49	0.09	0.40
H-402A	1.35	5.93	1.14	4.98	0.10	0.45	0.46	2.03	0.07	0.33
H-402B	1.56	6.83	1.31	5.74	0.12	0.52	0.53	2.33	0.09	0.38
H-407	2.45	10.74	2.06	9.02	0.19	0.82	0.84	3.67	0.13	0.59
B-802	7.63	33.41	6.41	28.06	0.58	2.54	2.61	11.42	0.42	1.84
B-803	7.44	32.59	6.25	27.38	0.57	2.48	2.54	11.14	0.41	1.79
CU Flare	1.84	8.04	9.99	43.76	0.25	1.10	34.14	149.5	3.78	16.56
HI-801	35.09	153.7	0.61	2.68	0.01	0.38	205.5	899.9	0.05	0.21
H-201	8.22	35.00	6.90	29.40	0.62	2.66	2.25	9.57	0.45	1.92
H-411	2.75	12.02	2.31	10.10	0.21	0.91	0.94	4.11	0.15	0.66
HI-81001	5.85	25.63	31.83	139.4	0.66	2.90	87.02	381.2	12.05	52.76
H-15001	10.85	47.53	8.80	38.54	2.19	9.57	9.83	43.04	1.58	6.93
H-210001	1.20	5.24	1.00	4.40	0.09	0.40	0.01	0.05	0.07	0.29
LPLT	----	----	----	----	----	----	----	----	90.41	396.0
HI-251*	75.87	332.3	52.31	229.1	52.56	230.2	313.8	1,374	----	Neg.
R-251*	32.15	140.8	----	Neg.	40.87	179.1	140.4	650.4	----	Neg.
EEQ8801	28.80	11.52	7.65	3.06	0.52	0.21	0.45	0.18	0.74	0.29
EEQ80001	9.16	3.66	1.97	0.79	0.64	0.26	0.10	0.04	0.75	0.30
Cat_Hop	----	----	----	----	9.18	40.20	----	----	----	----
CCR	0.83	3.65	0.12	0.54	0.39	1.73	0.47	2.04	0.03	0.14
C-80018	12.40	24.80	2.67	5.34	0.88	1.76	1.41	2.82	1.01	2.01
H-100024	0.68	2.96	1.11	4.87	0.10	0.44	0.45	1.98	0.07	0.32
Area 100	----	----	----	----	----	----	----	----	266.4	1,167
Area 550	----	----	----	----	----	----	----	----	17.83	78.10
Area 300	----	----	----	----	----	----	----	----	57.37	251.3
Area 400	----	----	----	----	----	----	----	----	90.41	396.0
Area 900	----	----	----	----	----	----	----	----	83.08	363.9
ASU	----	----	----	----	----	----	----	----	5.46	23.90
Area 250	----	----	----	----	----	----	----	----	48.40	212.0
TOTALS	323.6	1,236	188.8	781.2	114.8	496.2	821.8	3,628	684.3	2,989

* - Based on emissions from the BACT analysis.

TOTAL POTENTIAL EMISSIONS AFTER MODIFICATIONS

	NO _x		CO		PM ₁₀		SO ₂		VOC	
EU	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
T-83001	----	----	----	----	----	----	----	----	4.00	6.20
H-102B	7.97	34.90	11.12	48.70	1.64	7.19	4.52	19.81	0.73	3.19
H-102A	6.53	28.60	11.94	52.30	1.76	7.72	4.86	21.28	0.78	3.42
H-403	9.68	42.38	8.13	35.60	0.74	3.22	3.31	14.48	0.53	2.33
H-404	4.71	20.61	3.95	17.31	0.36	1.57	1.61	7.04	0.26	1.13
H-405	4.93	21.60	4.14	18.14	0.37	1.64	1.69	7.38	0.27	1.19
H-406	2.75	12.02	2.31	10.10	0.21	0.91	0.94	4.11	0.15	0.66
H-401A	1.57	6.87	1.32	5.77	0.12	0.52	0.54	2.35	0.09	0.38
H-401B	1.67	7.30	1.40	6.13	0.13	0.55	0.57	2.49	0.09	0.40
H-402A	1.35	5.93	1.14	4.98	0.10	0.45	0.46	2.03	0.07	0.33
H-402B	1.56	6.83	1.31	5.74	0.12	0.52	0.53	2.33	0.09	0.38
H-407	2.45	10.74	2.06	9.02	0.19	0.82	0.84	3.67	0.13	0.59
B-802	7.63	33.41	6.41	28.06	0.58	2.54	2.61	11.42	0.42	1.84
B-803	7.44	32.59	6.25	27.38	0.57	2.48	2.54	11.14	0.41	1.79
CU Flare	1.84	8.04	9.99	43.76	0.25	1.10	0.91	3.97	3.78	16.56
HI-801	9.36	41.03	23.05	101.0	0.46	2.03	7.98	34.94	8.72	38.20
H-201	19.56	85.67	8.65	37.87	0.78	3.43	3.53	15.44	0.57	2.48
H-411	2.75	12.02	2.31	10.10	0.21	0.91	0.94	4.11	0.15	0.66
HI-81001	1.90	8.34	10.36	45.38	0.27	1.20	0.94	4.11	3.92	17.17
H-15001	10.85	47.53	8.80	38.54	2.19	9.57	9.83	43.04	1.58	6.93
H-210001	1.20	5.24	1.00	4.40	0.09	0.40	0.01	0.05	0.07	0.29
LPLT	5.20	15.79	13.00	39.48	----	----	0.01	0.01	30.16	73.66
FGS-200	40.39	179.9	12.35	54.10	21.30	46.64	46.21	202.4	----	Neg.
EEQ8801	28.80	11.52	7.65	3.06	0.52	0.21	0.45	0.18	0.74	0.29
EEQ80001	9.16	3.66	1.97	0.79	0.64	0.26	0.10	0.04	0.75	0.30
Cat_Hop	----	----	----	----	0.43	1.88	----	----	----	----
CCR	0.83	3.65	0.12	0.54	0.39	1.73	0.47	2.04	0.03	0.14
C-80018	12.40	24.80	2.67	5.34	0.88	1.76	0.14	0.28	1.01	2.01
H-100024	0.68	2.96	1.11	4.87	0.10	0.44	0.45	1.98	0.07	0.32
Area 100	----	----	----	----	----	----	----	----	59.66	261.3
Area 550	----	----	----	----	----	----	----	----	3.01	13.2
Area 300	----	----	----	----	----	----	----	----	24.63	107.9
Area 400	----	----	----	----	----	----	----	----	17.99	78.8
Area 900	----	----	----	----	----	----	----	----	21.19	92.8
ASU	----	----	----	----	----	----	----	----	5.46	23.9
Area 250	----	----	----	----	----	----	----	----	7.12	31.2
TOTALS	205.2	713.9	164.5	658.5	35.4	101.7	97.0	422.1	198.6	791.9

TOTAL POTENTIAL CHANGES IN EMISSIONS AFTER MODIFICATIONS

	NO_x		CO		PM₁₀		SO₂		VOC	
EU	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Pre-Mod.	323.6	1,236	188.8	781.2	114.8	496.2	821.8	3,628	684.3	2,989
Post-Mod.	205.2	713.9	164.5	658.5	35.4	101.7	97.0	422.1	198.6	791.9
Changes	-118.4	-522.1	-24.30	-122.7	-79.4	-394.5	-724.8	-3,206	-485.7	-2,197

SECTION VI. PSD REVIEW

Over the years, TPI Petroleum, Inc. (TPI) has implemented numerous projects to improve the product quality and throughput at the Valero Ardmore Refinery. Based on a recent compliance analysis, TPI has identified several historical modifications, which resulted in emissions increases that triggered Prevention of Significant Deterioration (PSD) requirements. Therefore, the requirements of the PSD program must be addressed for each of these modifications. Some of the historical modifications and associated emissions increases were due to debottlenecking of upstream or downstream processes. Therefore, a full PSD analysis is not required for those projects because the associated emissions increases do not meet the definition of modification. Only projects for which there was a physical equipment modification are considered in this BACT analysis. The following modifications and associated pollutants are subject to PSD analysis:

Facility Modification	Pollutants Subject to PSD review
FCCU Catalyst Receiving Hopper	PM ₁₀
Crude Unit Heater H-102B	NO _x
Crude Unit Heater H-102A	NO _x
Crude Unit Fugitive Emissions	VOC
FCCU No. 1 Regenerator and CO Boiler/Incinerator	NO _x , CO, SO ₂ , PM ₁₀
FCCU No. 2 Regenerator	NO _x , CO, SO ₂ , PM ₁₀

The existing refinery was among the industries defined as a PSD-major source at an emissions level of 100 TPY. Full PSD review of emissions consisted of the following:

- a determination of best available control technology (BACT);
- an evaluation of existing air quality and a determination concerning monitoring requirements;
- an evaluation of PSD increment consumption;
- an analysis of compliance with National Ambient Air Quality Standards (NAAQS);
- an evaluation of source-related impacts on growth, soils, vegetation, and visibility;
- and a Class I area impact evaluation.

Current EPA policy is to require an emissions analysis to include mobile sources. In this case, the change in mobile source emissions was negligible. The facility was an existing facility. Few, if any, new employees were added. The added equipment required a small amount of maintenance traffic. The vast majority of the feedstock for the plant arrived by pipeline rather than by vehicle. Existing mobile source emissions have been treated as background emissions.

A. Best Available Control Technology

A BACT analysis was required for all pollutants emitted above PSD-significance levels for each of the modifications. BACT is generally defined as "an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any...source...which on a case-by-case basis is determined to be achievable taking into account energy, environmental, and economic impacts and other costs." A "top-down" analysis is the preferred method for determining BACT. The five basic steps of the top-down procedure are:

- Step 1. Identify all control technologies
- Step 2. Eliminate technically infeasible options
- Step 3. Rank remaining control technologies by control effectiveness
- Step 4. Evaluate most effective controls and document results
- Step 5. Select BACT

The first step is to identify all "available" control options for each modification/EU which triggering PSD for each pollutant under review. Available control options are those technologies or techniques with a practical potential for application to the EU. During the course of the BACT analysis, one or more control options may be eliminated from consideration. However, at the outset, a comprehensive list must be compiled. This list should include potentially applicable Lowest Achievable Emission Rate (LAER) technologies, innovative technologies, and controls applied to similar source categories.

The second step of the top-down analysis is to arrange the comprehensive list, created in Step 1, based on technical feasibility. The technical evaluation should clearly document the difficulties based on source-specific factors and physical, chemical, and engineering principles that preclude the safe and successful use of the control option. Technically infeasible control technologies are removed from further evaluation.

In the third step, all remaining control alternatives not eliminated in Step 2 are ranked and listed in descending order of control effectiveness. A list should be prepared for each emissions unit for each pollutant subject to BACT review. If the top ranked control option is proposed as BACT, other considerations need not be detailed.

In the fourth step, energy, environmental, and economic impacts are considered in order to arrive at the level of control. Beginning with the most stringent control option, both beneficial and adverse impacts are discussed and quantified. This process continues until the technology under consideration cannot be eliminated by any source-specific adverse impacts.

The final step is the selection of the most effective control option not eliminated by the four preceding steps as BACT for the pollutant and EU under review.

The EPA has consistently interpreted statutory and regulatory BACT definitions as containing two core requirements that the agency believes must be met by any BACT determination, regardless of whether it is conducted in a "top-down" manner. First, the BACT analysis must include consideration of the most stringent available control technologies (i.e., those which provide the "maximum degree of emissions reduction"). Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of energy, environmental, and economic impacts.

The BACT analysis evaluates control technologies/techniques for the following pollutants emitted from the sources identified above:

- PM₁₀ from the Fluid Catalytic Cracking Unit (FCCU) catalyst receiving hopper,
- NO_x emissions from Crude Unit heaters 102A and 102B,
- VOC emissions from the Crude Unit fugitive area, and
- NO_x, CO, SO₂, and PM₁₀ emissions from the FCCU two-stage regenerator.

All proposed and applied BACT must meet, at minimum, all applicable New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP). In some cases, technologies not sufficiently effective by themselves can be used in tandem to achieve BACT emission reduction levels.

The BACT analysis was originally submitted on December 28, 1998. It was later updated by a submittal on April 21, 2000, by Environmental Resources Management (ERM). This BACT analysis was accepted as submitted and incorporated into a consent order. Consent Order No. 02-007 required an updated application excluding the BACT which was accepted and approved by AQD. The updated application was submitted on July 23, 2002. The BACT analysis in this permit memorandum was based on and contains information from the analysis provided by ERM. Based on the BACT analysis the table below summarizes the BACT selected for the sources previously identified.

Selected BACT

Source	PSD Trigger Pollutant	Selected BACT
FCCU Catalyst Receiving Hopper	PM ₁₀	Cyclone and Wet Scrubber
Crude Unit Heaters H-102A and H-102B	NO _x	Ultra Low-NO _x Burners
Crude Unit Fugitive Emissions	VOC	Leak Detection and Repair
FCCU No. 1 Regenerator and CO Boiler/Incinerator	NO _x	Low-NO _x Burners for the CO Boiler and Control of Feedstock Hydrotreatment
	CO	Thermal Oxidation
	SO ₂	Wet Gas Scrubber
	PM ₁₀	Wet Gas Scrubber

Selected BACT (Cont.)

Source	PSD Trigger Pollutant	Selected BACT
FCCU No. 2 Regenerator	NO _x	Control of Feedstock Hydrotreatment
	CO	High Temperature Regeneration
	SO ₂	Wet Gas Scrubber
	PM ₁₀	Wet Gas Scrubber

FCCU Catalyst Receiving Hopper**PM₁₀**

1) Identification of All Available Control Technologies

Listed below are all the available control technologies for control of PM₁₀. After that a brief description of each control technology is given.

- Porous Sintered Media
- Baghouse
- Wet Gas Scrubber (WGS)
- Electrostatic Precipitator (ESP)
- Ionizing Wet Scrubber[®]
- Cyclone

Porous Sintered Media

Porous sintered media filters consist of multiple, rigid, high temperature, continuous flow filter elements housed in an exterior vessel designed to provide tertiary solids separation in place of a third-stage cyclone. Captured particulate is periodically removed from the filter elements to a hopper by any of various automated blowback techniques such as jet-pulse cleaning. The maximum allowable temperature for the filter media is 1,150 °F. The field efficiency, which must be verified by field-testing, is approximately 99.97% by weight.

Baghouse

A baghouse uses fabric filtration to remove particles from a gas stream. An airstream flows through a number of filter bags in parallel, where particulate collects on the fabric. The fabric serves primarily as a medium for a layer of particulate to collect. It is this layer of particulate that collects small particles from the stream. The units are modular in design, allowing the addition of units to accommodate changes in operation, and the units require a relatively low-pressure drop.

Wet Gas Scrubber

WGSs are used to reduce particulates (including SO₃). Flue gas enters the scrubbers where intensive gas/liquid contacting removes particulates by inertial impaction and/or condensation of liquid droplets on particles in the gas stream.

Electrostatic Precipitator

Electrostatic precipitation of particles involves four steps:

1. Conditioning the air stream to make it amenable to the ESP;
2. Ionizing particles in the air stream;
3. Collecting the charged particles on collector plates; and
4. Removing the charged particles from the plates, usually by rapping.

ESPs are common for use on large utility and industrial boilers, and produce a high level of efficiency in practice (greater than 90% under optimal operating conditions). They also have the advantage of a high efficiency rate for small particles and are effective for wet or dry streams over a wide range of gas temperatures.

Ionizing Wet Scrubber[®]

Ceilcote Air Pollution Control manufactures what they call an Ionizing Wet Scrubber[®] (IWS) which collects submicron particles, liquid particles, and gases by a combination of electrostatic charge, attraction, impaction, and gas absorption. In the Ceilcote IWS, high voltage ionization is used to electrostatically charge the particulate in the gas stream before passing through a crossflow scrubber section equipped with Tellerette[®] packing that absorbs gases and collects solid and liquid particles. Small particles (< 3 micron) are removed by attraction to the neutral surfaces of the packing and the scrubbing droplets. Larger particles (> 3 micron) are collected by inertial impaction. Gases in the stream are removed by physical and/or chemical absorption to the packing and scrubbing droplets. Typically, the IWS technology is estimated to remove less than 90% of PM₁₀.

Cyclone

Cyclones are used extensively for particle collection in industrial applications. Cyclones work by forcing particle-contaminated gas into a downward spiral within the unit. Centrifugal force and inertia force the particles in the gas outward toward the outer wall. Upon contact with the outer wall, the particles slide down and out the bottom of the cyclone. Due to the shape of the cyclone, gas changes direction to move upward in a smaller inner spiral. The cleaned gas exits through the top of the device and the separated particles exit through the bottom of the device.

Cyclones are commonly used because they are inexpensive, and the lack of moving parts keeps the maintenance requirements lower than other pollution control devices. However, because cyclones are inefficient for removal of small particles, they are used primarily for large particle-size streams or to pre-clean streams prior to treatment by another pollution control device.

2) Eliminate Technically Infeasible Control Technologies

Porous Sintered Media

A porous sintered metal filter is not a feasible technology for control of PM₁₀ from the catalyst hopper. The 60% moisture content of the gas stream is too high for porous sintered media to operate properly. A leading vendor of metal filters, Pall Corporation was contacted by the applicant, but declined to provide a quote for this application. Because a leading manufacturer

and vendor of porous sintered metal filters indicated that this technology is not appropriate for the catalyst hopper, porous sintered media was considered to be technologically infeasible for this application.

Baghouse

A baghouse is not a feasible technology for the control of PM₁₀ from the catalyst-receiving hopper. The catalyst hopper is driven by a steam ejector, and typically has a moisture content of approximately 60% as a result. Two vendors of baghouses, Saunco Air Technologies and Air Cleaning Specialists were contacted by the applicant to discuss the catalyst receiving hopper application. Both vendors declined to provide a quote and indicated that the moisture content would prevent the baghouse from achieving maximum removal efficiency. Because both vendors contacted by the applicant indicated that a baghouse is used primarily for dry processes and neither provided a quote for a baghouse for the catalyst receiving hopper, this technology was considered technically infeasible.

3) Rank Remaining Control Technologies

Feasible PM₁₀ Control Technologies

Control Technology	Estimated Control Efficiency
Wet Scrubber (WS)	>90%
Electrostatic Precipitator	>90%
Ionizing Wet Scrubber®	<90% (estimated)
Cyclone	50% *

* - Although cyclones may achieve much higher control efficiencies on streams with large particle sizes, the particulate emissions for the hopper consist mainly of small-size (<10 µm) particles. A cyclone is not expected to provide high efficiency particulate removal for this application.

4) Evaluate Remaining Control Technologies and Document Results

Wet Scrubber

The proposed BACT for PM₁₀ control from the catalyst feed hopper is a WS. A single WS will be used to control emissions from the FCCU No. 1 and No. 2 Regenerators and the Catalyst Receiving Hopper. The FCCU Catalyst Receiving Hopper is an intermittent source of PM. Emissions are small and only result during loading of FCCU catalyst into the fresh make-up catalyst hopper. Therefore, this unit can be controlled by venting it to the proposed control devices for the regenerators. Since this unit will be controlled by the proposed control device for the regenerators, all other control devices must be considered in addition to the WS and not as a PM₁₀ control technology by itself.

Electrostatic Precipitator & Ionizing Wet Scrubber®

As redundant control devices with similar control efficiencies as the WS, these control options are not considered further.

Cyclone

The FCCU Catalyst Receiving Hopper is currently controlled using a cyclone. The proposed controls for this unit include the cyclone in addition to the WS.

5) Select BACT

Proposed BACT Controls, Emission Limits, and Monitoring

Pollutant	Selected Technology	Emissions Limits (12-month rolling total)	Proposed Monitoring
PM ₁₀	Wet Scrubber and Cyclone	1.88 Tons/Year	Monitor 24-hour average WS liquid flow rate and pressure drop as parametric indicator of desired control efficiency. Indicator ranges to be determined based on future performance tests on actual installed control equipment.

The controls and emission limits proposed for the FCCU Catalyst Receiving Hopper are consistent with recent BACT determinations in the RACT/BACT/LAER Clearinghouse (RBLC).

Crude Unit Heaters H-102A and H-102B**NO_x**

1) Identification of All Available Control Technologies

Listed below are all the available control technologies for control of NO_x. After that a brief description of each control technology is given.

- Selective Catalytic Reduction (SCR)
- SCONO_xTM
- Ultra Low-NO_x Burners (ULNB)
- Selective Non-Catalytic Reduction (SNCR)
- Low-NO_x Burners (LNB)
- Flue Gas Recirculation (FGR)
- Low Excess Air (LEA)
- Steam Injection
- Reburning
- Staged Combustion

Selective Catalytic Reduction

EPA documentation states that, where applicable, SCR offers the highest percent reduction of the available NO_x reduction techniques. The SCR process is a post-combustion NO_x control technique which involves the mixing of anhydrous or aqueous ammonia (NH₃) vapor with flue gas (NO_x) and passing the mixture through a catalyst bed at temperatures between 600 and 800 °F to reduce NO_x to form molecular nitrogen (N₂) and water.

The most important factor affecting SCR efficiency is temperature. SCR can operate in a flue gas temperature window ranging from 500 to 1,100 °F according to EPA literature, although the optimum range for SCR is 625 to 700 °F. Temperatures below the optimum decrease catalyst activity and allow NH₃ to slip through. Temperatures above the optimum range oxidize NH₃ to form additional NO_x. SCR is also largely dependant on the stoichiometric ratio of NH₃ to NO_x. Variation of the ratio can reduce the removal efficiency of NO_x.

SCONO_xTM

Removal of NO_x using the SCONO_xTM system entails the catalytic oxidation of CO to CO₂ and NO to NO₂. The NO_x, which is reacted mainly to NO₂, is chemically reacted/adsorbed on the catalyst. NO_x is released from the catalyst as N₂. As of January 26, 2000, the SCONO_xTM system was in full-scale use in two locations. Both systems are used to control emissions from natural gas powered turbines with NO_x concentrations on the order of 25-30 ppm.

Ultra Low-NO_x Burners

ULNBs are designed to reduce the average oxygen concentration within the flame by recirculating hot, oxygen depleted, flue gas from the flame or firebox back into the combustion zone. This design maintains a flame temperature necessary for optimal combustion while reducing oxygen concentrations, and subsequently, fuel NO_x formation. ULNBs are reported to typically achieve lower emission rates than LNB. The EPA document, "Alternative Control Technologies Document for NO_x Emissions from Process Heaters," states that ULNBs may achieve a reduction of approximately 75% for thermal NO_x and 78% for natural draft fuel NO_x.

Selective Non-Catalytic Reduction

With SNCR, NO_x is selectively removed by the injection of NH₃ or urea (CO(NH₂)₂) into the flue gas at an appropriate temperature window of 1,700 to 1,900 °F and without employing a catalyst. Similar to SCR (with the exception of the catalyst bed), the injected chemicals selectively reduce the NO_x to N₂ and water. This approach avoids the problem related to catalyst fouling but the temperature window is critical for conducting the necessary chemical reaction. At the proper temperature, urea decomposes to produce the NH₃ that is responsible for NO_x reduction. At a higher temperature, the rate of a competing reaction, direct oxidation of NH₃ to form NO_x, becomes significant. This pollution control technology typically provides a control efficiency of approximately 40%. In SNCR, NH₃ is injected into the heater prior to convective heat recovery, where the temperature ranges from 1,600 to 2,000 °F. The effectiveness of SNCR similar to SCR is largely dependant on the temperature of the injection zone. A control efficiency of 70% can be achieved using SNCR while an efficiency of 35 to 60% is usually seen.

Low-NO_x Burners

One approach to reduce NO_x emissions is to utilize LNB. The ease or difficulty in replacing existing burners with LNB depends on a number of factors including space constraints and the extent to which air and/or electrical service may need to be modified.

LNB employ the same principle as two-staged combustion. Primary combustion takes place at a lower temperature under oxygen-deficient conditions, then combustion is completed at a higher temperature with excess air. The process takes place within the burner itself. LNB are designed to optimize the oxygen-fuel mixture within the burner. Like FGR and steam injection, LNB reduce the temperature of the flame to reduce the formation of thermal NO_x by up to 30% to 50%. LNB are ineffective on fuel NO_x formation.

Flue Gas Recirculation

FGR involves the return of 15% to 30% of the flue gas to the burners and the introduction of the gas mixture into the combustion zone. FGR reduces the peak flame temperature and the local oxygen concentrations. FGR effectively inhibits thermal NO_x formation, but has only a limited effect on fuel NO_x formation. FGR is generally incorporated into the design of new boilers rather than retrofitted onto existing boilers.

Low Excess Air

LEA operation is a combustion technique that optimizes the amount of air available and reduces the formation of thermal and fuel NO_x. Excess air can only be reduced to the point of some constraint, such as CO formation, flame length, or flame stability, and the level to which excess air must be reduced varies with the type of source. LEA is not generally considered an effective technology for refinery gas-fired sources, because variations in gas composition make maintaining stack O₂ levels difficult. LEA also has the disadvantages of increasing CO formation, and of offering little, if any reduction of NO_x emissions under many operating conditions. Under optimal conditions, NO_x emissions may be reduced by 1% to 15%.

Steam Injection

Steam or water injection is used to reduce the flame temperature, thereby reducing the formation of thermal NO_x. Water/steam injection is not effective in reducing fuel NO_x formation. Another version of this technique is to inject a water-in-oil emulsion, which operates on a similar principle as water/steam injection to reduce NO_x. This technique introduces water into the combustion process by emulsifying water in the fuel oil prior to its injection. The water emulsified in fuel oil reduces the flame temperature in the combustion zone thereby reducing thermal NO_x. However, water-in-oil emulsion is not effective in reducing fuel NO_x. For sources for which steam injection is appropriate, NO_x emissions may be reduced by up to 40% to 70%.

Reburning

The process of reburning requires about 15% to 20% of the fuel and air from a burner to be injected as separate streams downstream of the main flame. By injecting the fuel first, a rich combustion zone is created; the combustion air is injected later, returning the mixture to a fuel-lean environment. This scenario drives the destruction of NO in the combustion zone by

favoring the reaction to molecular nitrogen. The effectiveness of reburning as a NO_x control strategy depends on several factors including stoichiometry and temperature in the fuel-rich region. This technology has been used for NO_x control on coal-fired boilers. Under appropriate operating conditions, NO_x reductions of up to 50% to 60% may be achieved.

Staged Combustion

Staged combustion is a combustion control technology that aims to minimize conversion of fuel bound nitrogen to NO_x compounds. Typically, a portion of combustion air is diverted from the main burner and injected into the downstream portion of the flame. The fuel-rich region created in the flame causes fuel nitrogen to convert preferentially to N₂ rather than to NO_x. Under ideal conditions, staged air has been demonstrated to achieve from 12% to 71% NO_x reduction in process heaters. However, advances in LNB technology have allowed the incorporation of staged combustion into burner design, making this technology redundant to LNB or ULNB technologies. Staged combustion outside the context of LNB can be more technically challenging because it creates serious variations in heat flux and temperature, and requires frequent replacement due to corrosion of required piping in process heaters

2) Eliminate Technically Infeasible Control Technologies

SCONOXTM

The SCONOXTM system is unproven as a control technology for a crude unit heater. To date, the system has been used to control emissions from natural gas powered turbines and internal combustion engines but it has not been used to control emissions from crude unit heaters. Also, due to the greater amount of PM₁₀ emissions from the heaters fouling of the catalyst could result. The manufacturer does not represent this technology to be applicable to other uses other than turbines. Recently, the manufacturer of the SCONOXTM system announced that it no longer offers this control technology. Therefore, this technology is no longer available and will not be discussed further as a control technology for control of NO_x emissions.

Steam Injection

Steam injection is not an applicable technology for the crude unit heaters. Steam injection is used primarily in reducing NO_x from gas turbines, reciprocating engines and other internal combustion engines. The use of steam injection directly reduces the thermal efficiency of heaters, and is not used for this type of application as a result.

Reburning

Reburning is not considered technically feasible for the crude unit heaters. Reburning is used for control of NO_x in boilers, particularly coal-fired boilers. The Alternative Control Technology for Process Heaters document makes no mention of this technology and reburning was not found in the RBLC for this type of application. Therefore, reburning is not considered a demonstrated control technology.

Staged Combustion

Staged combustion is incorporated into ULNB and is not addressed further.

3) Rank Remaining Control Technologies

Potential NO_x Control Technologies

Control Technology	Estimated Control Efficiency
Selective Catalytic Reduction	>90%
Ultra Low-NO _x Burners (102A)	76% to 84%*
Ultra Low-NO _x Burners (102B)	68% to 79%*
Selective Non-Catalytic Reduction	25% to 70%**
Low-NO _x Burners	30% to 50%
Flue Gas Recirculation	15% to 30%***
Low Excess Air	1% to 15%

* - Based on stack testing.

** - Although the literature cites control efficiencies ranging from 25% to 70%, much lower efficiencies would be expected on the crude unit heaters because the initial NO_x concentrations are below the threshold at which SNCR is effective.

*** - Staged combustion is incorporated into the design of ULNB and is considered a redundant control technology.

4) Evaluate Remaining Control Technologies and Document Results

Selective Catalytic Reduction

Emissions of NH₃ or additional NO_x emissions are environmentally unsatisfactory situations especially if other pollution prevention technologies, such as ULNB, can be shown to offer comparable results. NH₃ odors will result from the process since NH₃ metering/monitoring is not yet sophisticated enough to control injection precisely, and the reaction is never 100% complete. Both stack and fugitive NH₃ odors would be perceptible in the areas surrounding the facility. In addition to NH₃ odors, a visible plume of fine ammonium sulfite/sulfate PM may result from this process. NH₃ storage can also be hazardous. NH₃ emissions could potentially be as high as 20 ppmv. Disposal of catalytic waste created from the SCR system will create an additional economic and environmental burden. The spent catalyst from the system must be replaced and disposed of at certain intervals. The SCR catalyst typically contains titanium or vanadium pentoxide. Vanadium pentoxide is considered a hazardous waste.

Ultra Low-NO_x Burners

As part of the compliance demonstration efforts made for the operating permit application, TPI installed UNLB in the heaters. The heaters were then stack tested after the installation of the burners. According to the stack tests, the existing UNLB on heater H-102A reduced the total annual emissions from a baseline of 118.3 TPY to approximately 28.6 TPY, a 76% reduction. An ULNB currently controls NO_x emissions from Crude Unit Heater H-102B. The existing ULNB on Heater H-102B reduces total annual NO_x emissions from a baseline emission rate of 110.1 TPY to approximately 34.9 TPY, a 68% reduction. Only an SCR system (90% efficient under optimum conditions) has higher control efficiency than the ULNB for heaters H-102A and H-102B. Since there are no solid or liquid waste streams associated with UNLB and this technology is currently employed at this facility, there are no additional energy, environmental, or economical impacts to be considered.

Selective Non-Catalytic Reduction

A control study performed at the Valero Ardmore Refinery indicated that the highest control efficiency that could be expected for the heaters using SNCR for the refinery-specific conditions would be only 30%.

Low-NO_x Burners

Since ULNB are currently used to control emissions of NO_x from the crude unit heaters, LNB are considered redundant and are not discussed further.

Flue Gas Recirculation

FGR has been used on few direct-fired heaters because it has several drawbacks. One of these drawbacks is that FGR can only be used on forced draft heaters because of the need to recirculate the flue gas. Since the Crude Unit heaters are both natural draft heaters, FGR is considered technically infeasible.

Low Excess Air

Due to the low control efficiencies of low excess air, it is not considered further.

Control Technology Combinations

Combinations of control technologies for these two units are not economically justified. While the cost of the controls remains the same, the decrease in emissions is very small. Therefore, the incremental cost of reducing the emissions with combined controls is exorbitant.

ULNBs that were installed on the crude unit heaters in 1998 are not considered in the baseline emissions calculated for the crude unit heaters since they were installed with the primary purpose of meeting BACT requirements. SCR was evaluated as a possible control alternative to ULNB but the calculated cost was significantly higher than the ULNB and was determined to not be economically justifiable. The economic impacts of the installation of a SCR system would be considerable. The retrofit of a SCR system on an existing combustion source can be costly and complex. The table below shows the heater, the control devices, the TPY reduction and the average cost effectiveness of the control device(s).

Heater	Control	Reduction (TPY)	Average Cost Effectiveness (\$/ton)
H-102A	SCR (90%)	106.5	\$12,694
	ULNB	89.7	\$1,784
	SCR & ULNB	115.4	\$13,048
H-102B	SCR (90%)	99.1	\$9,079
	SCR (80%)	88.1	\$8,178
	ULNB	75.2	\$1,975
	SCR & ULNB	106.6	\$9,629

An SCR of 80% removal efficiency was also investigated to determine if the lower cost unit would be cost effective. The cost savings realized by using a less efficient SCR system was not significant enough to make SCR an economically justifiable NO_x control option. Both the annualized cost and the incremental cost of the SCR system are well out of the range of BACT NO_x control costs for similar sources during the time frame that the BACT was submitted. In addition, ULNB is a proven technology on the heaters at the Ardmore Refinery.

5) Select BACT

Proposed BACT Controls, Emission Limits, and Monitoring

Pollutant	Unit	Selected Technology	Emissions Limits (12-month rolling total)	Proposed Monitoring
NO _x	102A	Ultra Low NO _x Burners	0.045 lb/MMBTU and 28.6 tons/year	Operate burners according to manufacturer specifications. Use emission factor reported by performance test and monthly fuel usage to calculate rolling 12-month total.
NO _x	102B	Ultra Low NO _x Burners	0.059 lb/MMBTU and 34.9 tons/year	

The emission limits are based on testing. Recent testing has confirmed that the heaters can meet these limits. The controls and emission limits proposed for the crude unit heaters are consistent with the BACT determinations issued during 2000 and 2001 in the RACT/BACT/LAER Clearinghouse.

Crude Unit Fugitive Emissions

VOCs

The most effective method for controlling fugitive emissions is periodic monitoring to locate leaking components followed by the prompt repair of any leaking equipment. Thus, the industry accepted standard BACT for VOC emissions from fugitives is a Leak Detection and Repair (LDAR) program. A LDAR program is currently implemented for the Crude Unit fugitive area. The existing LDAR program in the area of the Crude Unit is considered BACT for VOCs and is also considered the Maximum Achievable Control Technology (MACT). A full "top-down" BACT analysis for fugitive VOCs from the Crude Unit area is not performed because the currently implemented LDAR program meets the current industry fugitive VOC BACT standards. The crude unit area is also subject NSPS, Subpart GGG.

Proposed BACT Controls, Emission Limits, and Monitoring

Pollutant	Selected Technology	Leak Detection Thresholds	Proposed Monitoring
VOC	Leak Detection and Repair (OVA & Method 21)	500 or 10,000 ppm leak detection limits per NSPS Subpart GGG	Per NSPS Subpart GGG Frequencies

FCCU Regenerators

The FCCU consists of the riser, the reactor, a two stage regenerator system, air blowers, spent catalyst stripper, catalyst recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery. The FCCU regenerator at the TPI Ardmore refinery operates in two stages. The first regenerator stage operates in an oxygen deficient, partial burn mode. The second stage regenerator is a full-burn, or high temperature regeneration, operation.

The FCCU regenerator at the Ardmore refinery is subject to NSPS, Subpart J. The applicable NSPS maximum allowable emissions from a FCCU regenerator are listed below:

NSPS Limits For FCCU Regenerators

Pollutant	Emission Limit	Reference
PM ₁₀	1.0 lb/1,000 lb coke burn-off	40 CFR 60.102(a)(1)
CO	500 ppm _{dv}	40 CER 60.103(a)
SO ₂	90% reduction or 50 ppm _v	40 CER 60.104(b)(1)
	9.8 kg/1,000 kg coke burn-off	40 CFR 60.104(b)(2)
	0.3 wt % S in FCCU feedstock	40 CFR 60.104(b)(3)

Currently there are no NSPS or NESHAP regulations applicable to emissions of NO_x or VOC from the FCCU regenerators. There are currently three choices of control standards to meet the SO₂ NSPS requirements for the FCCU regenerators. The refinery is currently meeting the 0.3 wt % S in FCCU feedstock standard.

The resources consulted in the compilation of potential options for CO, NO_x, SO₂ and PM₁₀ control for the Ardmore refinery FCCU include the following:

- EPA's New Source Review Website
- The Maximum Achievable Control Technology (MACT) floor analysis included in the preamble to the proposed Part 63 Subpart UUU - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries – Catalytic Cracking (Fluid and Other) Units, Catalytic Reforming Units and Sulfur Plants
- U.S. EPA's RBLC database
- Texas Natural Resource Conservation Commission (TNRCC) FCCU BACT guidance
- South Coast Air Quality Management District (SCAQMD) FCCU BACT guidelines
- Control technology vendors
- Technical books and articles
- Other refineries with similar process limits

Additionally, the environmental agencies for Illinois, Indiana, Ohio, Michigan, Wisconsin, Arkansas, Oklahoma, New Mexico, and Louisiana were surveyed for guidance on BACT for FCCUs. All of these agencies indicated that they rely on the RBLC database as a basis for review of proposed BACT and that all determinations are made on a case-by-case basis. None of these states have any definitive BACT requirements or guidance for FCCUs.

FCCU No. 1 Regenerator and Thermal Oxidation System

NO_x

1) Identification of All Available Control Technologies

Listed below are all the available control technologies for control of NO_x from the FCCU No. 1 Regenerator system. A brief description of the control technology that has not already been described is given.

- Selective Catalytic Reduction (SCR)
- Ultra Low-NO_x Burners (ULNB)
- Selective Non-Catalytic Reduction (SNCR)
- Hydrotreatment
- Low-NO_x Burners (LNB)
- Flue Gas Recirculation (FGR)
- Low Excess Air (LEA)
- Steam Injection
- Reburning

Hydrotreatment

A hydrotreater entails the use of hydrogen gas with a catalyst to remove feed impurities. Hydrotreating is generally used to remove nitrogen- and sulfur-containing materials from feedstocks by selectively reacting these materials with hydrogen in a catalyst bed at high temperature. Hydrotreating reduces the formation of fuel nitrogen by reducing the overall nitrogen content of the feedstock, and efficiencies vary depending on the nitrogen content of the feedstock. Removing nitrogen from the feedstock is intended to eliminate NO_x emissions from nitrogen in fuel (fuel NO_x). It does not prevent oxidation of atmospheric nitrogen in combustion processes. The potential removal efficiency of a Hydrotreatment unit is estimated to be 50% to 85%.

2) Eliminate Technically Infeasible Control Technologies

SCR

SCR is considered a technically infeasible option for NO_x control due to the significant potential for catalyst fouling due to FCCU reversals. At the time of submittal, the RBLC bulletin board contained no entries of SCR being successfully used for control of NO_x from FCCU regenerators, despite the fact that several of the RBLC entries did employ either an ESP or a WS for particulate control, which could theoretically protect the SCR from catalyst reversals.

Information from equipment vendors and with South Coast Air Quality Management District (SCAQMD) also supports the fact that SCR is not an applicable control technology for FCCU emission streams. It should be noted, that the Exxon-Mobil Refinery in Torrance, California was issued a permit to install an SCR system on their FCCU by SCAQMD. However, the proposed SCR system has not yet begun operation and based on information from SCAQMD personnel, there will be no NO_x emission limits for the FCCU/SCR system. Instead, the Refinery will meet a facility wide NO_x limit. In addition, technical details of the FCCU design and operation are confidential according to both SCAQMD and Mobil-Exxon and are not available for purposes of this BACT analysis. Thus, no conclusions may be drawn regarding the similarity of Mobil-Exxon's FCCU system and the Ardmore Refinery's FCCU system. Furthermore, use of SCR at the Mobil-Exxon Refinery does not, on its own, indicate that SCR is applicable to the Ardmore Refinery's FCCU system. Based on the foregoing, SCR is not considered a feasible control technology for the Ardmore Refinery.

Steam Injection

Steam injection is considered a technically infeasible option for control of NO_x from the FCCU No. 1 Regenerator for two primary reasons. The first is that the increased moisture resulting from the steam is likely to result in equipment corrosion and affect CO Boiler destruction efficiency. The second is that steam injection has primarily been applied to date for control of NO_x from gas turbines. Steam injection is an appropriate technology for gas streams containing only trace levels of particulate. There are no entries identified in the RBLC bulletin board of the application of this technology being applied for the control of NO_x from FCCU regenerators. Communications with equipment vendors by the applicant also resulted in no identified cases of this technology ever being applied in practice to FCCU regenerators. Additionally, based on an independent study, even if this technology could be used on the FCCU No. 1 Regenerator system, its NO_x removal efficiency would be negligible.

Reburning

Because of the basic design of the regenerator, reburning is not considered a viable control technology for the regenerator itself. The effectiveness of reburning as a NO_x control strategy is dependant on mainly injection and mixing of secondary fuel into the combustion products coming from the main combustion zone and the thermal environment in the fuel-rich, secondary combustion zone. It is necessary to reduce the air in the fuel rich zone to approximately 90% excess air and for the temperature in the fuel rich zone to be approximately 2400 °F or higher. If the temperature is below this level, reduction of NO to N₂ will not occur. Because of heat extraction through the boiler walls, little if any thermal NO is formed by the second and third stage of combustion created by reburning. For the CO Boiler and Incinerator, it is possible to create the fuel rich environment but there is no way to create the approximate thermal environment. Therefore, reburning is not considered an effective control technique for the CO Boiler or Incinerator.

3) Rank Remaining Control Technologies

Potential NO_x Control Technologies

Control Technology	Estimated Control Efficiency
Hydrotreatment of Feedstock	50%
ULNB*	30% to 50% *
LNB*	30% to 50% *
SNCR	<30%
Low Excess Air	1% to 15%
Flue Gas Recirculation	Negligible**
Staged Combustion	Negligible**

* - LNB for the CO boiler are custom modified and incorporate beneficial aspects of ULNB design. LNB are equivalent to the ULNB and are not evaluated separately.

** - Under certain operating conditions these controls can increase the potential to emit of NO_x or CO.

4) Evaluate Remaining Control Technologies and Document Results

The most effective NO_x control technologies among the feasible options are LNB and the SNCR process. Because of the relative complexity of the Ardmore Refinery's FCCU system, there are a number of possible locations, or combinations of locations in which these pollution control devices might be installed. The NO_x reduction potential and cost effectiveness of SNCR and LNB are evaluated for several feasible locations in this section of the BACT analysis report. Although for some applications ULNB may achieve greater levels of NO_x reduction than LNB, the NO_x control technology study conducted at Ardmore Refinery indicates that this would not be true for the Refinery's CO Boiler. The CO Boiler would require modified LNB due to physical and operational boiler constraints. The NO_x technology study assessed a burner design that incorporates the NO_x reducing features of commercially available LNB and ULNB that would be applicable to the CO Boiler. Therefore, LNB and ULNB are considered equivalent technologies in this case, and the ULNB are not evaluated as a separate technology for this type of application.

Hydrotreatment of Feedstock

Hydrotreatment is already being used to treat the feedstock for the FCCU system. This reduces the amount of nitrogen containing materials in the coke and the emissions of NO_x and other nitrogen compounds from combustion of the coke in the regenerator and the regenerator off-gases in the CO Boiler/Incinerator. This is considered the baseline control technology for the FCCU No. 1 Regenerator. All other control technologies were reviewed in addition to this control technology.

ULNB and LNB

LNB are not options for the regenerator itself since it does not have burners or combust fuel using burners. The regenerator basically supplies oxygen to the catalyst to combust the deposits of coke on the catalyst. LNB are a hypothetically feasible technology for the CO Boiler and the Incinerator since they utilize burners to fire fuel in these units. LNB could theoretically replace the existing burners on the CO Boiler, the Incinerator, or on both units. However, the configuration of the Incinerator prevents the LNB burner technology from being used on this unit. According to the NO_x study, there is no commercially available burner that could be applied to the Incinerator, and no practical and economical way to modify the design of a LNB to make it effective for use in the Ardmore Refinery's Incinerator. As a result, the LNB technology is not considered technically feasible or commercially available for the Incinerator.

The existing burners on the CO Boiler could feasibly be replaced with a low NO_x design. Although the configuration of the boiler might require modifications to be made to existing LNB designs this technology could be used successfully on the CO boiler, with a control efficiency of between 30% to 50%. The cost per ton of NO_x removed by a LNB is estimated to be \$1,357 annually.

SNCR

A detailed NO_x assessment was completed by General Electric – Energy and Environmental Research Corporation (GE EER), the assessment indicated that SNCR is a feasible control technology for the CO boiler. As stated in the NO_x Control Technology Report, if SNCR were installed in the CO boiler, the technology would be likely to have serious, negative environmental impacts. The peak flame temperature in the CO boiler is not estimated to be high enough to maintain the temperature and residence time required for optimum SNCR performance. Consequently, significant NH₃ slip would be expected; if urea rather than NH₃ were utilized for the SNCR reagent, nitrous oxide (N₂O), a green house gas, will be emitted. Another implication of operating an SNCR system at low temperatures is that the SNCR reaction can consume radical species necessary for the oxidation of CO to CO₂. As a result, emissions of CO from the CO Boiler would increase. In theory, the temperature of the CO boiler could be increased to reduce these environmental impacts. However, increasing the temperature of the CO boiler would cause uncollected catalyst material to form slag deposits on convective sections of the boiler and effectively reduce the ability of the boiler to perform its primary function of producing steam. Increasing the temperature of the boiler would also require a decrease in the FCCU off-gas flow through the boiler so more flow would have to be diverted to the incinerator. Since there are no identified feasible NO_x controls for the incinerator beyond the existing hydrotreatment, diverting more flow through the incinerator would increase the NO_x emissions from the FCCU No. 1 Regenerator system.

In addition to these potential environmental impacts, an SNCR system installed in the CO Boiler would be expected to provide an overall control efficiency from the FCCU (including emissions from both the FCCU No. 1 and No. 2 Regenerators) of only approximately 15%. Installation of SNCR in the CO Boiler would not treat emissions from the FCCU No. 2 Regenerator, and would treat only 70% of the flow from the FCCU No. 1 Regenerator estimated to go to the CO boiler during full-load conditions. As a result, the cost effectiveness of this option would be

approximately \$4,984 per ton of NO_x. Therefore, in addition to the environmental impacts likely to result from operation of SNCR, the cost effectiveness of this option exceeded the typical costs incurred by other similar sources during the time frame that the BACT was submitted.

The other possible scenario for use of SNCR on the FCCU No. 1 Regenerator is to combine the streams from the CO Boiler and the Incinerator in such a way that the one-second retention time and 1,700 to 1,900 °F operating temperature required for efficient SNCR use are achieved. The most efficient way to achieve these conditions appears to be replacing the existing CO boiler with a larger CO boiler meeting the SNCR operating requirements. This option would cost approximately \$9,964/ton NO_x. Since the cost effectiveness of this option exceeds the costs incurred by other sources, this option was also eliminated based on energy and economic considerations.

Low Excess Air (LEA)

Since the FCCU No. 1 Regenerator is a partial burn regeneration unit and it basically uses air injection into the regenerator to combust the coke from the catalyst, the regenerator operates in a LEA environment. The amount of air into the regenerator is carefully controlled to keep the regenerator operating in an oxygen deficient/partial burn mode. Based on stack tests, the FCCU No. 1 Regenerator, CO Boiler, and Incinerator operate with low excess air. An increased reduction of excess air is expected to increase CO emissions dramatically.

Flue Gas Recirculation

FGR reduces the peak flame temperature and the local oxygen concentrations. FGR effectively inhibits thermal NO_x formation, but has only a limited effect on fuel NO_x formation. The FCCU regenerator already is operated in an oxygen deficient, partial burn mode. The majority of the NO_x from the regenerator is produced from fuel NO_x. For the CO Boiler, the regenerator off-gas acts much the same as recirculated flue gas. The peak flame temperature is already so low that thermal NO_x formation is expected to be negligible. Also, further suppression of the flame temperature would decrease the CO oxidation rate in the CO Boiler and would result in an increase in CO emissions. The incinerator operates in much the same way as the CO Boiler and would have the same concerns as the CO Boiler. Based on the reasons stated above FGR is not expected to significantly reduce formation of NO_x in the FCCU No. 1 Regenerator system and is not considered further.

Staged Combustion

Because of the basic design of the regenerator, staged combustion is not considered a viable control technology. The primary source of fuel nitrogen for the CO Boiler and the Incinerator is the regenerator off-gases. In the current configuration of the CO Boiler and Incinerator, regenerator off-gas is rapidly mixed with the available combustion air at approximately the same location as the fuel-gas flame front. Even if a significant portion of the combustion air was diverted downstream of the flame, the regenerator off-gas would be rapidly mixed with an excess quantity of oxidizer and would not result in a significant decrease in NO_x emissions.

Control Technology Combinations

Combinations of technologies must be examined for two primary reasons. First, the combination may provide increased removal efficiency of a pollutant. Second, the upstream control device in a combination may change a stream characteristic that would otherwise render the downstream control device infeasible. For example, an SCR is unable to handle high particulate loads, such as those that would be encountered when large quantities of catalyst were dumped during an upset. It is theoretically possible, that a particulate control device upstream of an SCR could allow the successful use of an SCR for this application.

In addition to the reasons for technical infeasibility presented earlier in this section, the reviewed combined control technologies would also have significant associated energy costs. For each of the combinations below, the cooler (and possibly saturated) gas leaving the upstream control device would have to be reheated to the high temperatures required for CO combustion (~1,800 °F). The additional heating required is not compatible with the successful operation of the existing CO Boiler/Incinerator. The FCCU regenerator off-gas is typically 1,100 °F, and thus already requires some additional heating within the CO Boiler or Incinerator. In addition, one must remove the SO₃ prior to removing particulates because as the air stream cools, sulfuric acid (H₂SO₄) will form and quickly cause detrimental damage to downstream equipment.

The review was limited to combinations that are known to be in use for a similar application, that are not redundant, and systems that would not be cost prohibitive. Control technologies reviewed in addition to the selected BACT (Hydrotreatment/LNB) to increase removal efficiencies of NO_x are SNCR, FGR, and LEA.

In theory, it is possible to use a combination of SNCR and LNB to control NO_x in the CO Boiler. According to a SNCR vendor, however, the maximum control that may be achieved by SNCR will reduce emissions to no lower than 20 ppm. Because the emissions in the CO Boiler have been measured at relatively low concentrations in the range of 55 to 60 ppm, and a LNB is expected to achieve approximately 50% reduction in NO_x levels, very little additional NO_x removal would be expected by adding an SNCR System. An SNCR System operating at its full capacity (a reduction to 20 ppm) would cost an additional \$13,212/ton of NO_x removed annually when combined with LNBs. Based on this high cost of removing the small quantity of additional NO_x, and on the environmental impacts discussed earlier, the combination of LNB and SNCR for the CO Boiler is neither economically nor environmentally justified.

Low excess air (LEA) combustion would not appreciably reduce NO_x emissions in combination with the proposed BACT because LEA is not considered an effective control for a unit fired with refinery fuel gas. Flue gas recirculation is not considered economically or technically feasible due to the minimal decrease in NO_x emissions and the increased CO emissions.

Combination of FCCU Regenerator StreamsSelective Catalytic Reduction

Combining the two FCCU regenerator streams will not eliminate any of the factors limiting the successful use of SCR at the Ardmore Refinery. SCR is not a feasible option for the combined FCCU regenerator streams.

Ultra Low-NO_x and Low-NO_x Burners

As with the FCCU No. 2 Regenerator, neither ULNB nor LNB are applicable to the combined regenerators' stream. The combined regenerators' stream does not employ burners, and because ULNB and LNB are only effective at reducing NO_x produced by the combustion of fuel by burners, neither ULNB nor LNB are considered a feasible control technology for a combined regenerator stream.

Hydrotreatment

Hydrotreatment is a technology used for removing nitrogen- and sulfur-containing materials from refinery feedstocks. Hydrotreatment is already being used to treat the feedstock for the FCCU system feedstock. Since there would be no additional feed associated with combining the off-gases from the FCCU No. 1 and 2 Regenerators, additional hydrotreatment would not be an applicable technology under this scenario.

Flue Gas Recirculation

FGR would not be applicable to a combined regenerators' stream. FGR reduces the formation of thermal NO_x which would not be expected to occur in the FCCU regenerators combined stack. Therefore, FGR is not considered a feasible control device for this scenario.

Steam Injection

Steam injection would not be applicable to a combined stream. Steam injection must be used to lower a flame temperature to reduce the formation of thermal NO_x. Since there is no flame in the stack, and NO_x is formed only in the individual regenerators, steam injection is not applicable to the combined stream.

Reburning

As with FGR and steam injection, reburning would not be applicable to the combined stream. Reburning is used to reduce NO_x formation in the combustion zone. Since there is no flame in the stack, and NO_x is formed only in the individual regenerators, reburning is not applicable to the combined stream.

Staged Combustion

Staged combustion is a combustion-control technology used to reduce the formation of NO_x from the combustion zone. Since there is no flame in the stack no NO_x formation is expected to occur in the stack, staged combustion is not an applicable control technology for the combined regenerators' stream.

5) Select BACT

LNB are proposed as BACT for the FCCU system. The LNB installed in the CO Boiler are expected to achieve an overall NO_x reduction of approximately 26%. The reduction in the CO boiler alone is expected to be between 30% to 50%.

LNB also do not have the potential for NH₃ or N₂O slip that SNCR does, and neither NO_x nor CO emissions are likely to be increased by the use of a LNB. SNCR if operated outside the optimum temperature range has this potential. Another environmental benefit of LNBs is that additional chemicals are not required for its use, in comparison to SNCR, which requires the storage and use of urea or NH₃. Based on the expected efficiency of LNB for NO_x control from the FCCU No. 1 Regenerator CO Boiler and on the environmental benefits in comparison to SNCR, LNB technology is proposed as BACT.

The NO_x concentration in the FCCU stack gas will be monitored using CEMS. Monthly-average values for stack gas NO_x and H₂O content, and stack gas flow rate will be used to calculate 12-month rolling total NO_x emissions for comparison to the proposed NO_x emission limit.

Proposed BACT Controls, Emission Limits, and Monitoring

Pollutant	Selected Technology	Emissions Limits (12-month rolling total)	Proposed Monitoring
NO _x	Feed Stock Hydrotreatment & Low-NO _x burners in the CO boiler.	216.0* tons/year	NO _x continuous emissions monitoring systems (CEMS). Compute 12-month rolling total NO _x emissions using monthly average NO _x concentration monitored along with monthly average H ₂ O concentration, and monthly average stack gas flow rate.

* - All NO_x emissions from the FCCU No. 1 Regeneration Unit are combined with the FCCU No. 2 Regeneration Unit. This number only represents the portion of NO_x contributed by the FCCU No. 1 Regenerator system.

CO

Carbon monoxide generation in the FCCU regenerator occurs from the incomplete thermal oxidation of carbon on the spent catalyst. Because the oxidation of CO to carbon dioxide (CO₂) generates significantly more heat than that of carbon (C) to CO, refiners typically operate regenerators under partial burn to maintain temperatures of the FCCU within the design specifications. TPI's FCCU No. 1 Regenerator is operated in partial burn to effect better control for FCCU temperatures than is practical from controlling fuel and oxygen feeds. The NSPS limit for CO is 500 ppmvd. Listed below are all the available control technologies for control of CO

from the FCCU No. 1 Regenerator. A brief description of the control technologies is also given. The refinery currently uses a combination of a CO Boiler and a CO Incinerator as baseline controls on the FCCU No. 1 Regenerator. The boiler and incinerator are operated in parallel to one another and share a common stack. The 1998 stack test data indicates an average flue gas CO concentration of 308 ppm_{dv}. This scenario is proposed as BACT for the FCCU No. 1 Regenerator.

1) Identification of All Available Control Technologies

- Catalytic Oxidation
- Thermal Oxidation
- High-Temperature Regeneration
- Combustion Promoter

Catalytic Oxidation

In catalytic oxidation, a catalyst enables the oxidation reaction to occur at much lower temperatures and at shorter residence times than in thermal oxidation. These conditions reduce operating costs, enable a smaller-sized system than thermal oxidation (incineration), and reduce construction material requirements. The most efficient catalysts are precious metals dispersed on high surface area washcoats that are bonded to ceramic honeycomb blocks. These catalysts are designed to operate between 600 °F to 1,200 °F and operating pressures up to 300 psig. Catalytic oxidation systems typically destroy 95% to 99% of CO and VOCs.

Thermal Oxidation (CO Boiler or CO Incinerator)

Thermal oxidation uses the concepts of temperature, time, and turbulence to achieve complete combustion. The combustion process is thought of as occurring in two separate stages: (1) the combustion of fuels, and (2) the combustion of pollutants. Use of a thermal oxidizer is equivalent to adding a combustion chamber where the regenerator vent gas is heated above its ignition temperature. Excess oxygen and additional fuel are supplied to reach this higher temperature and complete the conversion of CO to CO₂.

Partial burn FCCU regenerators operate at or below 1,250 °F. The lower operating temperatures result in regenerator vent gas CO concentrations well in excess of 500 ppm_{dv}. Once the vent gases pass through the thermal oxidizer, CO concentrations are comparable with those of a high temperature regeneration FCCU. For refiners operating a high temperature regeneration FCCU, a thermal oxidizer is not required because effluent CO concentrations are already less than 500 ppm_{dv}.

There are two types of thermal oxidizers currently used to control CO emissions from a partial burn FCCU regenerator, CO boilers and CO incinerators. CO boilers typically operate at approximately 1,800 °F to ensure complete conversion. CO incinerators typically operate between 1,600 and 2,000 °F. A CO boiler has an advantage over an incinerator in that the boiler also offers heat recovery for purposes of steam generation.

A thermal oxidizer has the disadvantage of being an additional combustion source. This increased fuel combustion, along with the high oxidizer operating temperatures, significantly increases the thermal NO_x emissions from the unit. It should be noted that the RBLC does not indicate the use of CO incinerators to meet BACT requirements for CO control. However, this may be due to an industry preference for the heat recovery capabilities that CO boilers offer.

High Temperature Regeneration

High temperature regeneration, or full combustion regeneration, uses excess oxygen and high operating temperatures, 1,300 to 1,400 °F, to reduce carbon deposits, or coke, on the FCCU catalyst and to complete the conversion of CO to carbon dioxide (CO₂). CO concentrations in high temperature regenerator effluents are usually 50 to 500 ppm_{dv}. Partial burn regenerators operate at approximately 1,250 °F with effluent CO concentrations in excess of 1,000 ppm_{dv}.

High temperature regeneration has some disadvantages. The unit must run at a lower catalyst/oil ratio because of the higher regenerator temperatures. There is an increased requirement for combustion oxygen and regenerators operating at maximum capacity may not be able to handle the increased air demand without upgrading the regenerator blower or installing an oxygen injection system. Also, for regenerators built prior to 1974, the higher operating temperatures may require more expensive metallurgy so as not to exceed the temperature rating of the regenerator internals.

CO Combustion Promoter

Combustion promoter is an additive injected into the circulating catalyst on an as-needed basis primarily to control regenerator afterburn and increase combustion efficiency. As a secondary benefit, combustion promoters slightly increase CO oxidation, thereby potentially reducing CO emissions from the regenerator under certain conditions. The promoter is an alumina or silica-alumina powder typically impregnated with platinum and/or palladium to catalyze the oxidation of CO to CO₂. Because the Ardmore Refinery regenerators control CO emissions to below NSPS levels by either thermal oxidation or full combustion, combustion promoter is not currently used.

2) Eliminate Technically Infeasible Control Technologies

Catalytic Oxidation

The primary problem with catalytic oxidizers is the loss of catalyst activity. They cannot be used on waste gas streams containing significant amounts of PM. PM deposits foul the catalyst and prohibit oxidation. Based on stack testing and expected FCCU upset conditions, the PM emission rate from the FCCU regeneration unit is such that it is considered technically infeasible to install a catalytic oxidation unit for control of CO emissions.

Though an upstream control device could significantly reduce the amount of PM that routinely passes through a catalytic oxidizer, the unit would still be susceptible to damaging PM concentrations during an FCCU “reversal” which is an upset condition where large quantities of catalyst are emitted. The infeasibility of catalytic oxidation for control of CO from FCCU regenerators was supported by a search of the RBLC Database. The RBLC Database contains no

record of catalytic oxidation being successfully used as a CO control for FCCU regenerators, despite the fact that several of the RBLC entries did employ either an ESP or a WS for particulate control. The applicant also contacted equipment vendors and other state agency's whom supported the position that catalytic oxidation is not applicable to FCCU regenerators.

High Temperature Regeneration

High temperature regeneration is not a feasible control option for the FCCU No. 1 Regenerator because in the two-regenerator system, the first regenerator is designed to operate in a wet, low temperature environment. Catalyst structure breaks down under high temperature and high moisture conditions, while its structure is protected if the temperature is kept relatively low in a high moisture environment. The second regenerator in the two-regenerator system is designed to operate at high temperature conditions, because the first regenerator has already removed the moisture.

The nature of the two-regenerator system favors high-temperature regeneration in the second regenerator, but prevents its implementation in the first regenerator. High temperature regeneration is not a feasible control technology for the FCCU No. 1 Regenerator.

3) Rank Remaining Control Technologies

Potential CO Control Technologies

Control Technology	Estimated Control Efficiency
Thermal Oxidation	> 95%
Combustion Promoter	Undetermined*

* - This technology is considered an augmentation technology and not necessarily a sufficient technology by itself.

4) Evaluate Remaining Control Technologies and Document Results

Thermal Oxidation (CO Boiler or CO Incinerator)

The most effective feasible control technology, thermal oxidation, is proposed as BACT for the FCCU No. 1 Regenerator. In 1985, TPI installed a boiler and a thermal incinerator to control CO emissions from the FCCU No. 1 Regenerator off-gas. The existing CO Boiler is a thermal oxidizer that converts the CO to CO₂ by combusting the stream with refinery fuel gas at 1,300 to 1,400 °F for about 1.6 to 2.2 seconds. Although a CO Boiler is currently used for the FCCU No. 1 Regenerator, it is not adequately sized to handle the entire flue gas stream during typical operation. As a result, a thermal incinerator is operated in parallel to the CO Boiler to handle the excess flow. The incinerator typically converts the CO to CO₂ with refinery fuel gas at approximately 1,400 °F for about 2 to 3 seconds. The CO Boiler and Incinerator emissions are vented through a common stack. Historically, the CO Boiler and Incinerator combination have been operated to maximize the steam production from the boiler rather than to achieve a CO emission rate lower than that required by NSPS. Consequently, there was a theoretical possibility that a new CO Boiler designed to handle the entire flue gas flow from the FCCU No. 1 Regenerator could provide greater reduction in CO than the existing system. A vendor quote and emission rate guarantee for a new unit was obtained for comparison to the existing system.

Recent CEMS data from the existing system indicate that it can be operated to achieve the guaranteed emission rate of a new, larger CO boiler. Therefore, the vendor guarantee for a new CO boiler was used only as a benchmark to indicate that the existing system can achieve emission levels comparable to a new thermal oxidation system. Reliance on this data does not imply that a new CO boiler must be used for CO control from the FCCU No.1 Regenerator but that the existing system can be used to achieve BACT.

It should also be noted that a new CO boiler would not be economically justified for control of CO from the FCCU No. 1 Regenerator. The annualized cost per ton of CO removed in comparison to the baseline would be \$9,179. Even when the economic benefit of additional steam production is taken into account, the annualized cost per ton of \$7,449 is clearly higher than the cost per ton of CO removed typically considered justified by a permitting agency. Because a new CO boiler is not economically justified, and because the existing thermal oxidation system can achieve comparable levels of CO control, the baseline CO control using the existing CO boiler and incinerator system is proposed as BACT.

Since there are no solid or liquid waste streams from the CO Boiler, there are no additional adverse environmental impacts to consider. Furthermore, a CO Boiler allows the flue gas from the FCCU No. 1 Regenerator to be used for steam production, thus having positive economic and energy impacts.

CO Combustion Promoter

While use of a combustion promoter can lower the CO content of the flue gas, it also has some drawbacks. The promoter has to be frequently added to the regenerator, two to three times a day, at a rate of 3 to 5 lb/ton of fresh FCCU catalyst. It increases the requirement for combustion air and raises the regenerator temperature; thus, increasing thermal deactivation of the catalyst. Finally, the use of CO combustion promoters can marginally increase NO_x emissions.

Use of CO promoters is not always technically feasible. For regenerators with vent gas CO concentrations already below 500 ppm_{dv}, refiners typically will not see appreciable reductions in CO emissions. Use of a CO combustion promoter to control CO emissions from the two stage regenerator at the TPI Ardmore facility is questionable. The first stage is designed to operate as a partial burn stage in an oxygen lean environment. Use of a CO combustion promoter requires excess oxygen and higher operating temperature than are available in the partial burn first stage. The flue gas from this first stage is already routed to a CO Boiler and Incinerator. If the combustion promoter were to decrease the CO concentration of the flue gas fed to the existing CO Boiler, this would mean an increase in supplemental fuel usage, which would cause an increase in thermal NO_x formation from the CO Boiler, since combustion of CO lowers the adiabatic flame temperature. An increase in NO_x formation and additional fuel requirements are an unacceptable compromise to control CO emissions from the first regenerator stage.

The second stage of the regenerator is a full burn stage and CO concentrations in the flue gas from this stage are already negligible. Therefore, use of a CO combustion promoter will offer no measurable reduction in CO emissions from the refinery's FCCU.

Combined Control Technologies

High temperature regeneration is already in use on the FCCU No. 2 Regenerator, and is not feasible on the FCCU No. 1 Regenerator. Combustion promoter would provide little if any additional CO removal to either regenerator. The FCCU No. 2 Regenerator already typically reduces CO levels to below detection limits. The existing thermal oxidation system would not reduce CO to lower levels with the addition of combustion promoter.

5) Select BACT

The baseline case of thermal oxidation is acceptable as BACT for the FCCU No. 1 Regenerator. Thermal oxidation is the feasible control technology having the highest control efficiency, and can achieve an emission level of 50 ppmv CO. Both the RBLC and communication with vendors by the applicant indicate that CO boilers and incinerators have been used successfully at refineries for CO control from FCCU regenerators.

While the upper range of the theoretical control efficiency for catalytic oxidation is slightly higher than for the baseline case, it is not appropriate for use at the Ardmore Refinery primarily due to the particulate loading from the FCCU regenerator. The BACT analysis indicates that thermal oxidation is the most effective control device that is both commercially available and appropriate for the source.

Proposed BACT Controls, Emission Limits, and Monitoring

Pollutant	Selected Technology	Emissions Limits (12-month rolling total)	Proposed Monitoring
CO	CO boiler and Incinerator	49.9* tons/year	CO continuous emission monitoring systems (CEMS). Compute 12-month rolling total CO emissions using monthly average CO concentration monitored along with monthly average H ₂ O concentration, and monthly average stack gas flow rate.

* - All CO emissions from the FCCU No. 1 Regeneration unit are combined with the FCCU No. 2 Regeneration unit. This number only represents the portion of NO_x contributed by the FCCU No. 1 Regenerator system.

SO₂

The coke on the spent catalyst that enters the FCCU regenerators typically contains some amount of sulfur, left over from the cracked feedstock. Sulfur oxides (SO_x), which consist primarily of SO₂, are formed in the FCCU regenerator by the oxidation of residual sulfur from the feed. At high regenerator temperatures, a small fraction (<10%) of SO₂ is converted to SO₃, a mist that acts as a particulate and can lead to opacity problems. SO₂ emissions can be controlled by

removing sulfur from feed or by removing it from the exhaust gases. There are several technologies available for the control of SO₂. Listed below are all the available control technologies for control of SO₂ from the FCCU No. 1 Regenerator. A brief description of the control technologies is also given.

1) Identification of All Available Control Technologies

- Wet Gas Scrubbers (WGS)
- Dry Scrubber (with ESP or baghouse)
- Ionizing Wet Scrubber[®]
- Hydrotreatment
- DeSO_x Catalyst Additive

Wet Gas Scrubbers

WGSs chemically remove SO₂ emissions using aqueous solutions. Flue gas enters the scrubber where intensive gas/liquid contacting removes sulfur oxides by absorption, neutralization, and partial oxidation to calcium sulfate. The most widely used scrubbing medium is limestone slurry, although some processes utilize other media. Wet scrubbing is a widely used control technology because a high level of efficiency may be achieved and because the costs are low relative to comparable technologies. SO₂ control efficiencies of 90% have been reported. The applicant received vendor information from two of the lead manufacturers of WS for refineries. Each system is briefly described below.

Belco Technologies Corporation

For SO₂ removal, Belco's EDV[®] Scrubber consists of an open spray tower equipped with proprietary nozzles that disperse a recycled alkaline solution that saturates the incoming stream to promote absorption of SO₂. The cleaned stream is then discharged to the atmosphere, while the scrubbing solution is treated and/or dewatered prior to discharge. The Belco system can remove greater than 90% SO₂.

Monsanto Enviro-Chem Systems, Inc.

The Monsanto DynaWave[®] system is a Calvert Collision Scrubber with an open design to handle large variations in stream composition. The vendor has indicated that greater than 90% removal of SO₂ is achievable. There are currently no Dynawave systems installed for FCCU off-gas treatment, according to EPA's RBLC and the vendor.

Dry Scrubber (with ESP or baghouse)

In dry scrubbing, a dry sorbent such as hydrated lime and water is injected into a venturi to remove SO₂ from the stream. Typically, lime slurry is injected into a venturi or duct to provide intimate mixing of flue gases and the sorbent. The SO₂ reacts with the sorbent in the wet phase. Inherent heat in the gas stream dries the slurry resulting in dry sorbent, which can be collected with an electrostatic precipitator (ESP) or fabric filter. SO₂ control efficiencies of 70% to 90% have been reported in the literature. The advantages of a dry scrubber include a reduction in water use and the generation of a dry waste that may be recyclable, depending on waste quality and regulatory classification and proximity of potential recyclers. Based on discussions by the

applicant with vendors and potential recyclers there is no market value to this waste, but it could potentially be recycled at a cost similar to conventional disposal methods.

Ionizing Wet Scrubber[®]

An Ionizing Wet Scrubber[®] is a type of WS that combines ionization with a chemical scrubbing agent. Adding ionization to a WS does not improve the efficiency of the scrubber to remove SO₂ from a gas stream. Ionization only improves the particulate removal capacity of the scrubber. From the perspective of SO₂ removal, a WS and an Ionizing Wet Scrubber[®] are identical technologies, and therefore are not considered separately for SO₂ removal in this report.

Hydrotreatment

Hydrotreating is generally used to remove materials from feedstock by selectively reacting these materials with hydrogen in a catalyst bed at high temperature. Hydrotreating reduces the formation of SO_x by reducing the overall sulfur content of the feedstock, and efficiencies vary depending on the sulfur content of the feedstock. Although one source reports that the theoretical removal efficiency of a hydrotreatment unit is estimated to be 50% to 70% for heavy desulfurization, the Ardmore Refinery hydrotreatment is designed to reduce the feedstock sulfur content from 2 wt% to 0.3 wt% for a potential control efficiency of 85%.

DeSO_x Catalyst Additive

Sulfur oxide transfer catalysts, or DeSO_x catalysts, are injected into the regenerator in small amounts to reduce SO_x emissions by about 40%. The DeSO_x additive adsorbs SO₂ and SO₃, which react on the surface with a metal oxide in the additive to form a metal sulfate. In the FCCU riser, the metal sulfate reacts with hydrogen to form H₂S, which is passed to a Sulfur Recovery Unit (SRU) for removal. The Ardmore Refinery hydrotreats its FCCU feed to reduce downstream SO₂ emissions rather than using a DeSO_x catalyst.

2) Eliminate Technically Infeasible Control Technologies

None of the SO₂ control technologies considered were eliminated as technically infeasible.

3) Rank Remaining Control Technologies

Potential SO₂ Control Technologies

Control Technology	Estimated Control Efficiency
Wet Gas Scrubber	>90%
Dry Gas Scrubber (with ESP*)	70% to 90%
Hydrotreatment	50% to 85%
DeSO _x Additive	38%

* - Although cyclones may achieve much higher control efficiencies on streams with large particle sizes, the particulate emissions for the FCCU and the CO Boiler consist mainly of small-size (<10 μ) particles. A cyclone is not expected to provide high efficiency particulate removal for this application.

4) Evaluate Remaining Control Technologies and Document Results

Hydrotreatment is already in use at the Ardmore Refinery and is considered the base case. Therefore, all other SO₂ controls are considered in addition to emission control benefits already provided by this control method. The most efficient SO₂ control option among the feasible technologies is a WS. Since this is considered an add-on control method that treats the exhaust gases from the regenerators, this method is evaluated for controlling both FCCU regenerator streams together and not separately. Each of the two proprietary systems has similar economic, environmental, and energy considerations.

Each of the two WS options requires a separate purge treatment unit (PTU) to treat the scrubbing liquid purge stream from the scrubber. In each case, this neutral purge stream is estimated to be approximately 20 gallons per minute (gpm) with chemical oxygen demand less than 100 ppm. The liquid waste stream quantity and composition will not overburden the refinery's existing wastewater treatment system. The additional electrical utilities and (makeup) water required to operate the WS are considered insignificant in comparison to the total refinery electrical and water demands. Because the most efficient option is being proposed as BACT, further discussion of the remaining technologies is not warranted. Also, since hydrotreatment of the feedstock and use of the WS are proposed as BACT, combined control technologies is also not discussed further. All other control would just be redundant.

The Belco EDV scrubber uses the concepts of saturation, expansion, condensation, and filtration to achieve SO₂ removal efficiencies of 90% or greater. The FCCU regenerator flue gas enters the EDV scrubber horizontally and is quenched and saturated in an open spray tower using a proprietary water spray nozzle design. SO₂ absorption takes place in the vertical portion of the spray tower. In the spray tower, the scrubbing liquid pH is generally controlled at pH 6 to 7 with an alkali. The staged intensive gas/liquid contacting provides the required desulfurization. The number of stages in the spray tower is determined by the desulfurization requirements.

The baseline emission rate was calculated based on stack tests extrapolated out to the maximum allowable throughput and sulfur concentrations of 30,000 bbl/day and 0.3 wt % sulfur in the feedstock. Baseline SO₂ emissions for FCCU No. 1 regenerator were based on the January 23, 1998, test results. Baseline SO₂ emissions for FCCU No. 2 regenerator were based on the August 12, 1999, test results. Installation of a Belco EDV scrubber would reduce emissions by 90%, incurring an average annual control cost for both regenerator streams of \$3,366/ton SO₂ removed.

5) Select BACT

By and large, WS are considered to be a very reliable form of SO₂ control for FCCU's. The primary adverse environmental impacts associated with the use of this WS are:

- Increased water usage
- Increased wastewater treatment
- Increased solid waste disposal

Wet gas scrubbing is an accepted form of SO₂ control for an FCCU regenerator despite these types of adverse collateral impacts. It is considered a MACT floor technology for the recently proposed 40 CFR Part 63 Subpart UUU - *National Emission Standards For Hazardous Air Pollutants from Petroleum Refineries - Catalytic Cracking (Fluid and Other) Units, Catalytic Reforming Units and Sulfur Plants*. Therefore, hydrotreatment and a Belco WS are acceptable as BACT for SO₂ from the FCCU No. 1 regenerator.

FCCU No. 1 Regeneration unit
Proposed BACT Controls, Emission Limits, and Monitoring

Pollutant	Selected Technology	Emissions Limits (12-month rolling total)	Proposed Monitoring
SO ₂	Hydrotreatment and Wet Scrubber	137.4* tons/year	SO ₂ continuous emission monitoring systems (CEMS). Compute 12-month rolling total SO ₂ emissions using monthly average SO ₂ concentration monitored along with monthly average H ₂ O concentration, and monthly average stack gas flow rate.

FCCU No. 2 Regeneration unit
Proposed BACT Controls, Emission Limits, and Monitoring

Pollutant	Selected Technology	Emissions Limits (12-month rolling total)	Proposed Monitoring
SO ₂	Hydrotreatment and Wet Scrubber	65.0* tons/year	SO ₂ continuous emission monitoring systems (CEMS). Compute 12-month rolling total SO ₂ emissions using monthly average SO ₂ concentration monitored along with monthly average H ₂ O concentration, and monthly average stack gas flow rate.

* - All SO₂ emissions from the FCCU No. 1 and No. 2 Regeneration units are combined together in one stack the individual numbers only represents the portion of SO₂ emissions contributed by each regenerator.

PM₁₀

Control of PM must be considered for the FCCU No. 1 Regenerator. PM₁₀ is one of the primary pollutants from FCCU regenerators. NSPS, Subpart J sets the emission limit of PM₁₀ from FCCU's at 1.0 lb/1000 lb coke burn-off. The FCCU No. 1 Regenerator PM emissions consist of the fine catalyst particles that have not been captured by the FCCU cyclone systems. The cyclone system is likely 99% efficient for particles greater than 10 microns in size. Therefore, this analysis focuses on PM₁₀. There are several technologies available for the control of PM₁₀. Listed below are all the available control technologies for control of PM₁₀ from the FCCU No. 1 Regenerator. A brief description of the control technologies not previously described for control of PM₁₀ emissions is also given.

1) Identification of All Available Control Technologies

- Porous Sintered Media
- Baghouse
- Dry or Wet Scrubber
- Electrostatic Precipitator
- Ionizing Wet Scrubber®
- Cyclone

Wet Gas Scrubber

The applicant has received vendor information from two of the lead manufacturers of WSs for refineries. Each system removes both SO₂ and particulate and is briefly described below. Since this is considered an add-on control method that treats the exhaust gases from the regenerators, this method is evaluated for controlling both FCCU regenerator streams together and not separately.

Belco Technology Corporation

For particulate removal, Belco's EDV® Scrubber consists of an open spray tower equipped with proprietary nozzles that disperse a recycled alkaline solution that saturates the incoming stream to promote impaction of large particles. For particulates, a second filtering module in series causes water from the saturated atmosphere to condense on the particles, making them easier to capture. The cleaned stream is then discharged to the atmosphere, while the scrubbing solution is treated and/or dewatered prior to discharge. The Belco system can achieve greater than 90% PM₁₀ removal.

Monsanto Enviro-Chem Systems, Inc.

The Monsanto DynaWave® system is a Calvert Collision Scrubber with an open design to handle large variations in stream composition. The vendor has indicated that greater than 90% removal of PM₁₀ is achievable. There are currently no Dynawave systems installed for FCCU off-gas treatment, according to RBLC and the vendor.

2) Eliminate Technically Infeasible Control Technologies

Porous Sintered Media

A California refiner has tested a porous sintered metal filter system as a FCCU third stage underflow filter. This underflow system, however, constituted no more than 3.0% of the total FCCU regenerator flue gas flow. Porous sintered metal filters have not been tested or implemented to date for PM₁₀ control from a full scale FCCU regenerator. This type of filter is expected to incur problems with FCCU startup and reversals and the filter media is not considered compatible with the high flow rates associated with an FCCU. Given the lack of commercially demonstrated reliability of this technology in a full-scale operation, it is considered a technically infeasible option for application to the FCCU regenerators.

Baghouse

A baghouse is considered a technically infeasible option for control of the FCCU No. 1 Regenerator or CO Boiler/Incinerator PM for this facility for a variety of reasons. The first is the high temperature of the exhaust gases. Normal exit gas temperatures from the FCCU regenerator and in the combined CO Boiler/incinerator stack are 1,100 °F and 900 °F, respectively. The primary reasons why baghouses are not used for FCCU regenerator or CO boiler applications are the temperature and moisture ranges of the emissions. The most readily available fabrics become damaged at temperatures over 500 °F, although some ceramic fabrics may withstand higher temperatures, moisture is a more significant problem because it causes “blinding” of the fabric bags. The combined CO Boiler/Incinerator stack gas contains approximately 11% water.

Representatives from AAF International, Donaldson-Torit Industries and Air Cleaning Specialists were contacted by the applicant for quotes for a baghouse for this type of application. AAF, Donaldson-Torit, and Air Cleaning Specialists declined to bid, stating that equipment was not available to address this type of source. Both temperature and flow rate were cited as factors. Born Environmental noted that the fabric filter material they generally used would withstand sustained temperatures of approximately 500 °F. Fabric filters that could withstand sustained temperatures of 850 °F could be obtained for approximately three to four times the cost of the standard fabric (approximately \$60-\$80/ft², in comparison to \$20/ft²). Temperatures significantly above these levels would result in damage to the filter bags or fire.

More importantly, although particulate loadings under baseline conditions would not be expected to result in undue damage to the filter bags, high loadings of abrasive catalyst associated with FCCU reversals would result in damage whether the baghouse was placed before or after the existing CO Boiler. The vendor indicated that any upsets including reversals, which involved significantly greater quantities of PM than the 40.1 lb/hr reported by the January 1998 stack test, would require a shutdown or bypass of the unit.

Finally, a review of the RBLC bulletin board and communications with equipment vendors and the state contacts by the applicant did not result in identification of a single instance where baghouses had been applied successfully in practice for the control of particulate matter from FCCU regenerators. Because a vendor could provide a baghouse for this application, it is considered commercially available. However, because they are not a demonstrated technology

for a similar source, and because leading industrial vendors declined to provide an unqualified quote, the use of a baghouse was considered not applicable to this type of source.

Cyclone

Because the FCCU regenerator already contains two stages of cyclones for recovering catalyst, additional cyclones (in series or in parallel) would be redundant. Since cyclones are not efficient for removal of small particles, redundancy is not expected to provide additional control of small particles.

3) Rank Remaining Control Technologies

Potential PM₁₀ Control Technologies

Control Technology	Estimated Control Efficiency
Wet Gas Scrubber	>90%
Wet Gas Scrubber with ESP*	>90%
Ionizing Wet Scrubber®	<90% estimated

* - A WS is selected for SO₂ control. Because a WS is also effective at PM₁₀ control, an ESP is a redundant particulate control technology and must be considered in addition to the WS and not as a PM₁₀ technology by itself.

4) Evaluate Remaining Control Technologies and Document Results

Consistent with the BACT process the two most efficient options were evaluated further: a WS alone and a WS combined with an ESP system. Thus, energy, environmental, and economic factors were assessed to select the BACT for PM₁₀. An ESP alone is not considered because the WS is proposed as BACT for SO₂ control. Since a WS is also an efficient PM₁₀ control device, an ESP would be a redundant particulate control technology and must be considered in combination with the WS rather than as a PM₁₀ technology by itself. Energy requirements were taken into consideration to estimate annual operating costs per ton removed. Using an ESP in addition to a WS, greatly increases the energy requirements for a marginal increase in PM₁₀ removal. Assuming a WS alone would only reduce total annual tons of PM₁₀ from 594 to less than 111 TPY, combining a WS with a 90% efficient ESP (for the front half of the sampling train) would reduce PM₁₀ to about 69 TPY. The capital cost for a WS including site preparation costs is estimated to be about \$19.8 million and for a WS combined with an ESP would be approximately \$25.8 million. Taking into account both the annual operating costs and the initial capital costs, the annual cost per ton of PM₁₀ removed for these two options are \$12,675/ton and \$14,133/ton respectively. Therefore, the annual cost for the combined WS-ESP option exceeds the costs incurred by other sources. Accordingly, this option is eliminated based on energy and economic considerations. The environmental benefit of additional PM₁₀ removal by an ESP cannot be justified given the economic penalty the ESP would impose. This is illustrated by considering the incremental cost of reducing PM₁₀ emission further from 111 TPY with a WS to 69 TPY. Assuming additional removal of 42 TPY with an ESP, the incremental addition to the annual cost for this additional removal, referred to as the marginal cost effectiveness, is nearly \$31,000 for a 90% efficient ESP system, which is clearly exorbitant.

WGSs are, therefore, more cost effective than an ESP and WS combination. A WS would be characterized by the energy and environmental aspects noted above. Two WS vendors (Belco and Monsanto) have specified WS systems that are reported to control PM₁₀ to greater than 90% and potentially up to 99%, respectively. The four most recent RBLC FCCU technology determinations have been WSs.

The cost effectiveness of the particulate matter control scenarios was evaluated in detail for the purpose of this analysis and are summarized below.

Cost Effectiveness of PM₁₀ Control Options

No.	Control Scenario	PM₁₀* Removal (ton/yr)	Annualized PM₁₀ Cost Effectiveness** (\$/ton removed)	Marginal Cost Effectiveness compared to Scenario 2 (\$/ton)	Marginal Cost Effectiveness compared to Scenario 3 (\$/ton)
1	90% WS+ 99% ESP	530	\$15,126	\$145,767	\$40,921
2	90% WS+ 90% ESP	526	\$14,133	---	\$30,936
3	90% WGS	484	\$12,675	---	---

* - Includes front and back half of the sampling train and an estimated control of 50% for the back half of the sampling train for the wet scrubber.

** - The Belco WS quote, which provided the most complete accounting of installed capital costs, was used in the calculations.

The Scenario 1 and Scenario 2 cost effectiveness values of \$15,126/ton and \$14,133/ton, respectively, are considered economically unreasonable and have not been previously imposed by AQD for similar applications. The high cost of the WS alone, however, is warranted since it also removes SO₂ emissions.

5) Select BACT

A WS is also proposed as BACT for PM₁₀ control on the combined FCCU regenerators stack. A WS is the most effective commercially available and appropriate control device for the FCCU regenerators at the Ardmore Refinery. The PM₁₀ control efficiency for the proposed WS is 90%. The RBLC database shows that four analyses made during the time that the BACT analysis was submitted proposed WS as BACT for PM₁₀. Three of these are in combination with cyclones, which are already in place at the Ardmore Refinery.

As discussed for SO₂ control, the alternative of two WSs, one for each FCCU stack, was also evaluated. The two-scrubber scenario would not remove a greater percentage of PM₁₀ than the single-scrubber scenario, but would be far more expensive. The cost per ton of PM₁₀ removed when two scrubbers are used is \$25,350, in comparison to \$12,675 for the single-scrubber scenario. Given that two scrubbers do not remove more PM₁₀ than a single scrubber, the use of a WS on each individual FCCU stack is not economically justified.

FCCU No. 1 Regeneration unit
Proposed BACT Controls, Emission Limits, and Monitoring

Pollutant	Selected Technology	Emissions Limits (12-month rolling total)	Proposed Monitoring
PM ₁₀	Cyclones and Wet Scrubber (>90% efficient)	26.2* tons/year	Monitor 24-hour average WS liquid flow rate and pressure drop as parametric indicators of desired control efficiency. Indicator ranges to be determined based on future performance tests on actual installed control devices.

FCCU No. 2 Regeneration unit
Proposed BACT Controls, Emission Limits, and Monitoring

Pollutant	Selected Technology	Emissions Limits (12-month rolling total)	Proposed Monitoring
PM ₁₀	Cyclones and Wet Scrubber (>90% efficient)	20.4* tons/year	Monitor 24-hour average WS liquid flow rate and pressure drop as parametric indicators of desired control efficiency. Indicator ranges to be determined based on future performance tests on actual installed control devices.

* - All PM₁₀ emissions from the FCCU No. 1 and No. 2 Regeneration units are combined together in one stack the individual numbers only represents the portion of PM₁₀ emissions contributed by each regenerator. The BACT analysis only represents the front-half of the PM₁₀ sampling train.

FCCU No. 2 Regenerator

Since all of the pollutants and related control technologies for the FCCU No. 1 Regenerator and the FCCU No. 2 Regenerator are the same, all of the determinations for the FCCU No. 2 Regenerator will start from the eliminated technically infeasible control techniques. Also, since SO₂ and PM₁₀ emissions from the FCCU No. 2 Regenerator were addressed with the FCCU No. 1 Regenerator, they are not covered in this section also. Only emissions of NO_x and CO are addressed in this section.

NO_x

1) Eliminate Technically Infeasible Control Technologies

SCR

SCR is considered a technically infeasible option for NO_x control for the FCCU No. 2 Regenerator for the same reasons it was determined infeasible for the FCCU No. 1 Regenerator.

ULNB and LNB

Neither LNBs nor ULNBs are applicable to the FCCU No. 2 Regenerator because the regenerator does not employ burners to burn fuel. Because LNBs and ULNBs are not effective at reducing NO_x other than that produced by the burning of fuel, ULBs and LNBs are not considered a feasible control technology for the FCCU No. 2 Regenerator.

Flue Gas Recirculation

FGR is not a feasible technology for the control of NO_x from the FCCU No. 2 Regenerator. The FCCU No. 2 Regenerator is designed to run at high temperatures to oxidize CO to CO₂. Because FGR is designed to reduce temperature to prevent the formation of thermal NO_x, it would reduce the FCCU No. 2 Regenerator's ability to function as designed and its ability to oxidize CO. In addition, even if FGR was implemented in the FCCU No. 2 Regenerator, it is not expected to be very effective due to the low temperature differential that would be expected across the unit. Because heat is not removed from the flue gas to produce steam, as is the case in a boiler, the temperature exiting the FCCU is not expected to be significantly lower than the temperature of the gas in the reaction chamber. Recirculating the flue gas to the regenerator inlet would not have the desired effect of lowering the reaction temperature and reducing the formation of thermal NO_x.

Steam Injection

The use of steam injection is not feasible for use on the FCCU No. 2 Regenerator because it would interfere with the operation of the unit. The FCCU No. 2 Regenerator is able to operate at a higher temperature than the FCCU No. 1 Regenerator because it operates dry. The catalyst's structure breaks down in a combination of moisture and heat. The FCCU No. 2 Regenerator is operated dry so that it can be operated at higher temperatures (full burn) without breakdown of the catalyst structure. Introduction of steam or water into the FCCU No. 2 Regenerator would cause the breakdown of catalyst under current operating conditions. If the FCCU No. 2 regenerator were to be modified to accommodate steam injection, it would no longer be able to operate as a full burn regenerator and would not thermally oxidize CO as it was designed.

2) Rank Remaining Control Technologies

Potential NO_x Control Technologies

Control Technology	Estimated Control Efficiency
SNCR	30 to 60%
Hydrotreatment of Feedstock	50%
Low Excess Air	1% to 15%
Reburning	Negligible
Staged Combustion	Negligible

3) Evaluate Remaining Control Technologies and Document Results

SNCR

The annualized cost per ton of NO_x removed with SNCR installed on the No. 2 FCCU regenerator alone would be \$7,710. The cost effectiveness of this option exceeds the costs incurred by other sources during the time frames that the BACT was submitted and which are regulated by AQD.

The relatively high cost per ton of NO_x removed is due in large part to the fact that the gas stream must be heated prior to introduction to the SNCR system. The annual estimated cost of heating the FCCU No. 2 Regenerator off-gas is nearly \$100,000. In addition to the economic impacts, heating the gas stream would introduce additional pollutants to the stream, increasing the load to downstream pollution control devices, or if SNCR is downstream of pollution control devices, additional pollutants would be discharged to the atmosphere. Operating the SNCR at a temperature lower than the optimum range of 1,700 °F to 1,900 °F will result in the emission of unreacted urea, known as “urea slip.”

Because the environmental and economic impacts of SNCR are unjustifiably high for the FCCU No. 2 Regenerator alone, SNCR is not an appropriate technology for use on the No. 2 FCCU regenerator alone.

Hydrotreatment of Feedstock

Hydrotreatment is already being used to treat the feedstock for the FCCU system. This reduces the amount of nitrogen containing materials in the coke and the emissions of NO_x and other nitrogen compounds from combustion of the coke in the regenerator. This is considered the baseline control technology for the FCCU No. 2 Regenerator. All other control technologies were reviewed in addition to this control technology.

Low Excess Air (LEA)

Since the No. 2 Regenerator is a full burn regeneration unit. It basically uses air injection into the regenerator to combust the coke from the catalyst. Use of LEA in the FCCU No. 2 Regenerator would cause the regenerator to no longer be able to operate as a full burn regenerator and would not thermally oxidize CO as it was designed. The amount of air into the regenerator is carefully controlled to keep the regenerator temperature below a certain level.

Reburning & Staged Combustion

Because of the basic design of the regenerator, reburning and staged combustion are not considered viable control technologies. There are no burners in the regenerator and combustion of the coke in the FCCU No. 2 regenerator is effected by adding air to the regenerator.

Combination of FCCU Regenerator Streams

These scenarios were addressed in the “FCCU No. 1 Regenerator” section.

Control Technologies Combinations

There are no applicable control technology combinations for the FCCU No. 2 Regenerator.

4) Select BACT

The baseline case of feed stock hydrotreatment is acceptable as BACT for the FCCU No. 2 Regenerator.

Proposed BACT Controls, Emission Limits, and Monitoring

Pollutant	Selected Technology	Emissions Limits (12-month rolling total)	Proposed Monitoring
NO _x	Feedstock Hydrotreatment	140.8* tons/year	NO _x continuous emissions monitoring systems (CEMS). Compute 12-month rolling total NO _x emissions using monthly average NO _x concentration monitored along with monthly average H ₂ O concentration, and monthly average stack gas flow rate.

* - All NO_x emissions from the FCCU No. 2 Regeneration Unit are combined with the FCCU No. 1 Regeneration Unit. This number only represents the portion of NO_x contributed by the FCCU No. 2 Regenerator.

CO

1) Eliminate Technically Infeasible Control Technologies

Catalytic Oxidation

SCR is considered a technically infeasible option for CO control for the FCCU No. 2 Regenerator for the same reasons it was determined infeasible for the FCCU No. 1 Regenerator.

3) Rank Remaining Control Technologies

Potential CO Control Technologies

Control Technology	Estimated Control Efficiency
High Temperature Regeneration	> 95%
Combustion Promoter	Undetermined*

* - This technology is considered an augmentation technology and not necessarily a sufficient technology by itself.

3) Evaluate Remaining Control Technologies and Document Results

High Temperature Regeneration

The FCCU No. 2 Regenerator uses high temperature regeneration to oxidize CO. The FCCU No. 2 Regenerator is extraordinarily efficient at oxidizing CO. In a January 1998 stack test, CO was measured in three runs, two of which did not report CO in detectable levels, the other reported a concentration of 0.04 ppmv. Because high temperature regeneration is extremely

efficient for removal of CO from the FCCU No. 2 Regenerator, replacement of, or addition to high temperature regeneration is not warranted for CO control.

CO Combustion Promoter

Use of CO promoters is not always technically feasible. For regenerators with vent gas CO concentrations already below 500 ppmvd, refiners typically will not see appreciable reductions in CO emissions. The FCCU No. 2 Regenerator is a full burn regenerator and CO concentrations in the flue gas from this stage are already negligible. Therefore, use of a CO combustion promoter will offer no measurable reduction in CO emissions from the refinery's FCCU.

Combined Control Technologies

High temperature regeneration is already in use on the No. 2 regenerator. Combustion promoter would provide little if any additional CO removal. The No. 2 regenerator already typically reduces CO levels to below detection limits. The existing thermal oxidation system would not reduce CO to lower levels with the addition of combustion promoter.

4) Select BACT

The baseline case of high temperature regeneration is acceptable as BACT for the FCCU No. 2 Regenerator.

Proposed BACT Controls, Emission Limits, and Monitoring

Pollutant	Selected Technology	Emissions Limits (12-month rolling total)	Proposed Monitoring
CO	High Temperature Regeneration	4.2* tons/year	CO continuous emission monitoring systems (CEMS). Compute 12-month rolling total CO emissions using monthly average CO concentration monitored along with monthly average H ₂ O concentration, and monthly average stack gas flow rate.

* - All CO emissions from the FCCU No. 2 Regeneration unit are combined with the FCCU No. 1 Regeneration unit. This number only represents the portion of CO contributed by the FCCU No. 2 Regenerator.

B. Air Quality Impacts

The Valero Ardmore Refinery is located in Carter County, which is currently designated attainment or unclassified for all criteria pollutants, and there are no areas classified as non-attainment within 50 kilometers of the refinery. As part of the Refinery's Title V application due diligence, it was determined that past modifications at the Ardmore Refinery may have resulted in emission increases of NO_x, CO, PM₁₀, SO₂, and VOC sufficient to trigger the Prevention of Significant Deterioration (PSD) requirements codified in 40 CFR Part 52.

Prevention of Significant Deterioration (PSD) is a construction-permitting program designed to ensure air quality does not degrade beyond the National Ambient Air Quality Standards (NAAQS) or beyond specified incremental amounts above a prescribed baseline level. The PSD rules set forth a review procedure to determine whether a source will cause or contribute to a violation of the NAAQS or maximum increment consumption levels. If a source has the potential to emit a pollutant above the PSD significance levels, then they trigger this review process. EPA has provided modeling significance levels (MSL) for the PSD review process to determine whether a source will cause or contribute to a violation of the NAAQS or consume increment. Air quality impact analyses were conducted to determine if ambient impacts would be above the EPA defined modeling and monitoring significance levels. If impacts are above the MSL, a radius of impact (ROI) is defined for the facility for each pollutant out to the farthest receptor at or above the significance levels. If a radius of impact is established for a pollutant, then a full impact analysis is required for that pollutant. If the air quality analysis does not indicate a radius of impact, no further air quality analysis is required for the Class II area.

ERM prepared an air quality analysis in accordance with the procedures and methodology presented, which are consistent with guidance provided by the Oklahoma Department of Environmental Quality (ODEQ) and Environmental Protection Agency (EPA). The results of this air quality analysis show that the proposed emissions under this permit will not cause or contribute to an exceedance of the National Ambient Air Quality Standards (NAAQS) or significant PSD increment consumption.

VOC is not limited directly by NAAQS. Rather, it is regulated as an ozone precursor. EPA developed a method for predicting ozone concentrations based on VOC and NO_x concentrations in an area. The Scheffe tables utilize increases in NO_x and VOC emissions to predict increases in ozone concentrations. The ambient impacts analysis utilized the tables from "VOC/NO_x Point Source Screening Tables" (Richard Scheffe, OAQPS, September, 1988).

Modeling Methodology

The refined air quality modeling analyses for the Valero Ardmore Refinery employed USEPA's Industrial Source Complex (ISC3) (Version 02035) model (USEPA, 1995a). The ISC3 model is recommended as a guideline model for assessing the impact of aerodynamic downwash (40 CFR 40465-40474). The regulatory default option was selected such that USEPA guideline requirements were met.

The stack height regulations promulgated by USEPA on July 8, 1985 (50 CFR 27892), established a stack height limitation to assure that stack height increases and other plume dispersion techniques would not be used in lieu of constant emission controls. The regulations specify that Good Engineering Practice (GEP) stack height is the maximum creditable stack height which a source may use in establishing its applicable State Implementation Plan (SIP) emission limitation. For stacks uninfluenced by terrain features, the determination of a GEP stack height for a source is based on the following empirical equation:

$$H_g = H + 1.5L_b$$

where:

H_g = GEP stack height;

H = Height of the controlling structure on which the source is located, or nearby structure; and

L_b = Lesser dimension (height or width) of the controlling structure on which the source is located, or nearby structure.

Both the height and width of the structure are determined from the frontal area of the structure projected onto a plane perpendicular to the direction of the wind. The area in which a nearby structure can have a significant influence on a source is limited to five times the lesser dimension (height or width) of that structure, or within 0.5 mile (0.8 km) of the source, whichever is less. The methods for determining GEP stack height for various building configurations have been described in USEPA's technical support document (USEPA, 1985).

The heights of some of the exhaust stacks at the refinery were evaluated to determine if they are less than respective GEP stack heights, a dispersion model to account for aerodynamic plume downwash was necessary in performing the air quality impact analyses.

Since downwash is a function of projected building width and height, it is necessary to account for the changes in building projection as they relate to changes in wind direction. Once these projected dimensions are determined, they can be used as input to the ISC3 model.

In October 1993, USEPA released the Building Profile Input Program (BPIP) to determine wind direction-dependent building dimensions. The BPIP program was used to determine the wind direction-dependent building dimensions for input to the ISC3 model.

The BPIP program builds a mathematical representation of each building to determine projected building dimensions and its potential zone of influence. These calculations are performed for 36 different wind directions (at 10 degree intervals). If the BPIP program determines that a source is under the influence of several potential building wakes, the structure or combination of structures that has the greatest influence ($H + 1.5 L_b$) is selected for input to the ISCST3 model. Conversely, if no building wake effects are predicted to occur for a source for a particular wind direction, or if the worst-case building dimensions for that direction yield a wake region height less than the source's physical stack height, building parameters are set equal to zero for that wind direction. For this case, wake effect algorithms are not exercised when the model is run. The building wake criteria influence zone is $5 L_b$ downwind, $2 L_b$ upwind, and $0.5 L_b$ crosswind. These criteria are based on recommendations by USEPA. The building cavity effects were then used in the modeling analysis for the refinery. For this analysis, the first step was to determine the building cavity height based on the formula:

$$h_c = H + 0.5L_b$$

where:

- h_c = GEP stack height;
- H = Height of the controlling structure on which the source is located, or nearby structure; and
- L_b = Lesser dimension (height or width) of the controlling structure on which the source is located, or nearby structure.

If the stack height was greater than or equal to the cavity height, the cavity effect would not affect the downwind maximum impacts.

The meteorological data used in the dispersion modeling analyses consisted of five years (1986, 1987, 1988, 1990, and 1991) of hourly surface observations from the Oklahoma City, Oklahoma, National Weather Service Station and coincident mixing heights from Oklahoma City (1986-1988) and Norman, Oklahoma (1990 and 1991).

Surface observations consist of hourly measurements of wind direction, wind speed, temperature, and estimates of ceiling height and cloud cover. The upper air station provides a daily morning and afternoon mixing height value as determined from the twice-daily radiosonde measurements. Based on NWS records, the anemometer height at the Oklahoma City station during this period was 6.1 meters.

Prior to use in the modeling analysis, the meteorological data sets were downloaded from the USEPA Support Center for Regulatory Air Models (SCRAM) website. This data was scanned for missing data, but no missing data were found. USEPA used the procedures outlined in the USEPA document, "Procedures for Substituting Values for Missing NWS Meteorological Data for Use in Regulatory Air Quality Models," were used to fill gaps of information for single missing days. For larger periods of two or more missing days, seasonal averages were used to fill in the missing periods. The USEPA developed rural and urban interpolation methods to account for the effects of the surrounding area on development of the mixing layer boundary. The rural scheme was used to determine hourly mixing heights representative of the area in the vicinity of the refinery.

The urban/rural classification is used to determine which dispersion parameter to use in the model. Determination of the applicability of urban or rural dispersion is based upon land use or population density. For the land use method the source is circumscribed by a three kilometer radius circle, and uses within that radius analyzed to determine whether heavy and light industrial, commercial, and common and compact residential, comprise greater than 50 percent of the defined area. If so, then urban dispersion coefficients should be used. The land use in the area of the proposed facility is not comprised of greater than 50 percent of the above land use types and is considered a rural area.

The refined modeling used a nested Cartesian grid. Receptors were placed no greater than 50 meters apart along the boundary. From the fence line, a 100-meter grid of receptors extended out to 500 meters. A 500-meter grid extended beyond this grid, out to 2.5 kilometers from the site. A 1,000-meter grid extended beyond this grid, out to 10 kilometers from the site. Beyond that, a

spacing of 2.5 kilometers was used extending out to 50 kilometers from the facility. This modeling was used to define the radius of significant impact for each pollutant. All receptors were modeled with actual terrain data. The terrain data was taken from United States Geologic Survey (USGS) 7.5-minute Digital Elevation Model Files. A total of 20 modeling runs were performed for this modeling analysis.

Summary of Modeling Emission Inventory

For each modeling analysis type (e.g., Preliminary Analysis, NAAQS or PSD Increment) varying modeling emission inventories were developed (e.g. contemporaneous increases, increases over baseline, or total emissions). However, the stack parameters for point sources in each inventory were modeled using actual stack parameters, with the exception of some pseudo-point type sources (e.g., tanks), that were modeled to represent their non-buoyant, low velocity type emissions. A discussion of the sources included in each modeling analysis is presented below.

Preliminary Analysis

Typically for PSD Preliminary Analyses, contemporaneous changes (i.e., changes within three years of the triggering event) in emissions are modeled. However, as mentioned previously, an evaluation of historic changes at the Refinery showed that changes at the facility that occurred as early as 1982 may have required permitting under PSD regulations. For the purposes of this modeling project, the contemporaneous changes in emissions modeled in the significance analysis were defined as the proposed emissions under this permit application minus the two-year average past actual emissions for mid-1980 to mid-1982. Tabulations of the emission inventories for the PSD preliminary analyses of NO₂, SO₂, PM₁₀, and CO were provided in the application.

On-Property Sources – Full Impact Analyses

Available air permitting and emissions inventory documentation was reviewed to identify on-property sources of NO₂, SO₂, and PM₁₀. For the NAAQS analyses, the identified on-property sources were modeled at their proposed allowable emission rates. For the PSD Increment analyses, the identified on-property sources were modeled at their increment-consuming emission rate. The increment-consuming emission rate was estimated by subtracting the historical two-year average emission rate from the proposed allowable emission rate. The on-property source emission inventories for the Full Impact Analyses were provided in the application.

Off-Property Sources – Full Impact Analyses

Off-property sources located within a radius defined by the AOI plus 50 kilometers were included in the Full Impact PSD Increment and NAAQS Analyses that were triggered by the Preliminary Analyses. An ODEQ database retrieval, ODEQ emission inventory reports, and ODEQ permitting files were used to identify applicable sources to be included in the modeling analyses and their respective stack parameters and emission rates. Off-property sources other than those at Atlas were assumed to be increment consuming, and allowable emission rates were included in the model.

Due to its proximity to the Refinery (contiguous to the south), sources at Atlas were evaluated to assess whether they were increment-consuming sources or whether they were existing emission sources prior to the minor source baseline date. Information from Atlas permit applications was used to assess construction, reconstruction, and modification dates for Atlas' emission sources. A summary of the analysis that were used to evaluate the sources included in the PSD Increment Analysis for each pollutant and a summary of the off-property modeling emission inventories for the impact analyses (PSD Increment and NAAQS) were provided in the application.

Preliminary Analysis

The first step in the PSD modeling analysis was the Preliminary Analysis (AOI analysis). In this analysis emission increases were modeled to evaluate whether the resultant highest predicted concentrations for each pollutant averaging period combination were of regulatory significance.

These results were also used to evaluate the extent of the modeling analysis that would be required. A significant receptor file was created using either the ISCST3 "MAXIFILE" output option and/or BEE-Line's graphical (*.grf) interface for the ISCST3 model. This file contained each predicted concentration that was greater than the MSL, the receptor location, time, date and year. The results of the Preliminary Analysis were used to evaluate whether a Full Impact Analysis was required to define the resultant AOI for modeling purposes, and to evaluate whether a full analysis would be required. The results of the Preliminary Analysis are summarized below.

Preliminary Analysis Results

Pollutant	Averaging Period	Max. Predicted Concentration ($\mu\text{g}/\text{m}^3$)	PSD MSL ($\mu\text{g}/\text{m}^3$)	AOI (km)	Monitoring Exemption Levels ($\mu\text{g}/\text{m}^3$)
NO ₂	Annual	11.0	1	4.0	14
CO	1-hour	1,255	2,000	N/A	N/A
	8-hour	331.0	500	N/A	575
SO ₂	3-hour	84.0	25	0.9	N/A
	24-hour	10.2	5	0.8	13
	Annual	0.2	1	N/A	N/A
PM ₁₀	24-hour	23.5	5	2.1	10
	Annual	1.7	1	2.0	N/A

The results predicted ambient CO concentrations to be less than the MSL for the both the 1-hour and 8-hour averaging periods and the ambient SO₂ concentrations to be less than the MSL for the annual averaging period. Thus a Full Impact Analysis was not required for CO (1-hour or 8-hour) or for SO₂ (annual). The predicted ambient concentrations for NO₂ (annual), SO₂ (3-hour and 24-hour), and PM₁₀ (24-hour and annual) averaging periods were greater than the MSL. Since regulatory-significant concentrations were predicted for NO₂, PM₁₀, and SO₂ for the applicable averaging periods, a Full Impact Analysis was performed for each. The Full Impact Analysis included only those receptors where the preliminary modeled concentrations were predicted to be significant.

Full Impact Analysis (PSD Increment and NAAQS)

A Full Impact Analysis was performed to predict ambient concentrations for comparison to the NAAQS and PSD increment. This modeling analysis addressed emissions from the Valero Refinery's sources and off-property sources within the radius defined by the AOI plus 50 kilometers. The highest second high impacts were evaluated for the SO₂ short-term PSD Full Impact Analyses. The highest sixth high impacts were evaluated for short-term PM₁₀ analyses, per EPA's Pre-1997 PM₁₀ Method. The highest annual concentrations were evaluated for the long-term analyses for each pollutant.

If the modeling results predicted an exceedance of a standard, the receptor-averaging period for each predicted exceedance was compared to the significant receptor file created in the Preliminary Analysis to evaluate whether the Valero Refinery was predicted to be significant for the receptor averaging period combination at which the exceedance was predicted. If the predicted concentrations for the Valero Refinery were not significant for a receptor averaging period combination when an exceedance was predicted, the Valero Refinery was not considered to be contributing to the exceedance. The reported concentration was then identified using the significant receptor-averaging period combination with the highest predicted concentrations in the full analysis.

Air Quality Monitoring Data

The preliminary modeling conducted as part of this analysis resulted in predicted concentrations that were above the modeling significance levels for NO₂ (annual), PM₁₀ (24-hour and annual), and SO₂ (3-hour and 24-hour) averaging periods. Background concentration data was obtained from the ODEQ, Air Quality Division for NO₂, PM₁₀, and SO₂ for each of the applicable averaging periods. Since pre-construction monitoring is not possible for a retroactive PSD permit and pre-construction monitoring would only delay installation of control equipment, Air Quality allowed the use of monitoring data collected from the Ponca City Area. Ponca City and Ardmore are of a similar size and have similar source impacts. The monitoring data should provide conservative background data for the NAAQS analysis and are shown below. Post-construction monitoring will be required in the permit for those pollutants that exceeded the monitoring exemption levels. The background concentrations were added to the modeled results to demonstrate compliance with the NAAQS and increment consumption.

Summary of Background Concentrations

Pollutant	Averaging Period	Monitored Concentration (µg/m³)
NO ₂	Annual	13.2
PM ₁₀	24-hour	72.0
	Annual	24.0
SO ₂	3-hour	140.4
	24-hour	62.6

PSD NAAQS Full Impact Analyses

This section provides the results of the PSD NAAQS Analyses. A discussion of each of the pollutants included in the analysis (NO₂, SO₂, and PM₁₀) is provided.

NO₂ NAAQS Analysis

A summary of the annual NO₂ NAAQS modeling analysis is provided below.

NO₂ NAAQS Analysis Results

Averaging Period	NAAQS (µg/m³)	Background (µg/m³)	Max. Predicted Concentration (µg/m³)	Predicted Conc. & Background (µg/m³)
Annual	100	13.2	27.9	41.1

The highest predicted ambient concentration plus background was less than the NAAQS. Thus, no further analysis was required for the NO₂ NAAQS.

PM₁₀ NAAQS Analysis

A summary of the 24-hour and annual PM₁₀ NAAQS modeling analyses is provided below.

PM₁₀ NAAQS Analysis Results

Averaging Period	NAAQS (µg/m³)	Background (µg/m³)	Max. Predicted Concentration (µg/m³)	Predicted Conc. & Background (µg/m³)
24-hour	150	72	62.7	134.7
Annual	50	24	9.1	33.1

1) 24-Hour Analysis

The highest predicted ambient concentration plus background was less than the NAAQS. Thus, no further analysis was required for the 24-Hour PM₁₀ NAAQS.

2) Annual Analysis

The highest predicted ambient concentration plus background was less than the NAAQS. Thus, no further analysis was required for the annual PM₁₀ NAAQS.

SO₂ NAAQS Analysis

A summary of the 3-hour, 24-hour, and annual SO₂ NAAQS modeling analyses is provided below.

SO₂ NAAQS Analysis Results

Averaging Period	NAAQS (µg/m³)	Background (µg/m³)	Max. Predicted Concentration (µg/m³)	Predicted Conc. & Background (µg/m³)
3-hour	1,300	140.4	567.9	708.3
24-hour	365	62.6	99.6	162.2

1) Three-Hour Analysis

The highest predicted ambient concentration plus background was less than the NAAQS. Thus, no further analysis was required for the three-hour NAAQS.

2) 24-Hour Analysis

The highest predicted ambient concentration plus background was less than the NAAQS. Thus, no further analysis was required for the 24-hour NAAQS.

PSD Increment Analysis

This section provides the results of the PSD Increment Analysis. The following sections discuss in more detail the methodology and results for each of the pollutants included in the analysis.

NO₂ PSD Increment Analysis

A summary of the annual NO₂ PSD Increment Analysis is provided below.

NO₂ Increment Analysis Results		
Averaging Period	Maximum Predicted Conc. ($\mu\text{g}/\text{m}^3$)	PSD Increment ($\mu\text{g}/\text{m}^3$)
Annual	22.7	25

The highest predicted ambient concentration plus background was less than the PSD increment. Thus, no further analysis was required for the annual NO₂ PSD increment.

PM₁₀ PSD Increment Analysis

A summary of the annual PM₁₀ PSD increment modeling analysis.

PM₁₀ Increment Analysis Results		
Averaging Period	Maximum Predicted Conc. ($\mu\text{g}/\text{m}^3$)	PSD Increment ($\mu\text{g}/\text{m}^3$)
24-hour	26.2	30
Annual	5.1	17

1) 24-Hour Analysis

The highest predicted ambient concentration plus background was less than the PSD increment. Thus, no further analysis was required for the 24-hour PM₁₀ PSD increment.

2) Annual Analysis

The highest predicted ambient concentration plus background was less than the PSD increment. Thus, no further analysis was required for the annual PM₁₀ PSD increment.

SO₂ PSD Increment Analysis

A summary of the annual SO₂ PSD increment modeling analysis is provided below.

SO₂ Increment Analysis Results		
Averaging Period	Maximum Predicted Conc. ($\mu\text{g}/\text{m}^3$)	PSD Increment ($\mu\text{g}/\text{m}^3$)
3-hour	142.8	512
24-hour	60.0	91

1) Three-Hour Analysis

The highest predicted three-hour ambient concentration plus background was less than the PSD increment. Thus, no further analysis was required for the three-hour SO₂ PSD increment.

2) 24-Hour Analysis

The highest predicted 24-hour ambient concentration plus background was less than the PSD increment. Thus, no further analysis was required for the three-hour SO₂ PSD increment.

Summary of Modeling Results

Pollutant	Analysis	Averaging Period	Standard (µg/m³)	Ambient Impact (µg/m³)¹
NO ₂	NAAQS	Annual	100	41.1
	Increment	Annual	25	22.7
PM ₁₀	NAAQS	24-hour	150	134.7
	NAAQS	Annual	50	33.1
	Increment	24-hour	30	26.2
	Increment	Annual	17	5.1
SO ₂	NAAQS	3-hour	1300	708.3
	NAAQS	24-hour	365	162.2
	Increment	3-hour	512	142.8
	Increment	24-hour	91	60.0

¹ - Ambient Impacts include background concentrations.

F. Evaluation of Source-Related Impacts on Growth, Soils, Vegetation, & Visibility

Mobile Sources

Current EPA policy is to require an emissions analysis to include mobile sources. In this case, mobile source emissions are expected to be negligible. The number of employees needed beyond those currently employed is insignificant.

Growth Impacts

The purpose of the growth impact analysis is to quantify the possible net growth of the population of the area as a direct result of the project. This growth can be measured by the increase in residents of the area, the additional use and need of commercial and industrial facilities to assist the additional population with everyday services, and other growth, such as additional sewage treatment discharges or motor vehicle emissions.

Approximately 50 trade jobs (i.e., welders, electricians, construction workers, etc.) over a 24 month period will be needed to complete the construction of the project. It is anticipated that the majority of these jobs will be local hires, thus not requiring any additional residential or commercial capacity within the area. No full-time positions are expected. There should be no increase in community growth or the need for additional infrastructure. Therefore, it is not anticipated that the project will result in an increase in secondary emissions associated with non-project related activities or growth.

Ambient Air Quality Impact Analysis

The purpose of this aspect of impact analysis is to predict the air quality in the area of the project during construction and after commencing operation. This analysis follows the growth analysis by combining the associated growth with the emissions from the proposed project and the emissions from other permitted sources in the area to predict the estimated total ground-level concentrations of pollutants as a result of the project, including construction.

The only source of additional emissions may be from fugitive dust generated from equipment transportation or vehicles during construction. Any long-term air quality impact in the area will result from emissions increases due to operation of the facility. These impacts have been analyzed in preceding sections.

Soils and Vegetation Impact

The primary soil units in the area of the Refinery are Amber very fine sandy loam and Dale silt loam. The main crops typically grown on the soils identified within the area of interest are native grasses, and cultivated crops. No sensitive aspects of the soil and vegetation in this area have been identified. As such, the secondary National Ambient Air Quality Standards (NAAQS), which establish ambient concentration levels below which it is anticipated that no harmful effects to either soil or vegetation can be expected, are used as the benchmark for this analysis.

The effects of gaseous air pollutants on vegetation may be classified into three rather broad categories: acute, chronic, and long-term. Acute effects are those that result from relatively short (less than 1 month) exposures to high concentrations of pollutants. Chronic effects occur when organisms are exposed for months or even years to certain threshold levels of pollutants. Long-term effects include abnormal changes in ecosystems and subtle physiological alterations in organisms. Acute and chronic effects are caused by the gaseous pollutant acting directly on the organism, whereas long-term effects may be indirectly caused by secondary agents such as changes in soil pH.

SO₂ enters the plant primarily through the leaf stomata and passes into the intercellular spaces of the mesophyll, where it is absorbed on the moist cell walls and combined with water to form sulfurous acid and sulfite salts. Plant species show a considerable range of sensitivity to SO₂. This range is the result of complex interactions among microclimatic (temperature, humidity, light, etc.), edaphic, phenological, morphological, and genetic factors that influence plant response (USEPA, 1973).

NO₂ may affect vegetation either by direct contact of NO₂ with the leaf surface or by solution in water drops, becoming nitric acid. Acute and chronic threshold injury levels for NO₂ are much higher than those for SO₂ (USEPA, 1971).

The secondary NAAQS are intended to protect the public welfare from adverse effects of airborne effluents. This protection extends to agricultural soil. The modeling conducted, which demonstrated compliance with the Primary NAAQS simultaneously demonstrated compliance with the Secondary NAAQS because the Secondary NAAQS are higher or equal to the Primary NAAQS. Since the secondary NAAQS protect impact on human welfare, no significant adverse impact on soil and vegetation is anticipated.

Visibility Impairment

Visibility is affected primarily by PM and NO_x emissions. The area near the facility is primarily agricultural, consisting of pastureland. Some residences are located southeast and east of the facility. The closest airport is located approximately 3 miles north-northeast of the facility. Therefore, there are no airports, scenic vistas, or other areas that would be affected by minor reductions in visibility. The project is not expected to produce any perceptible visibility impacts in the vicinity of the plant. The project is actually expected to reduce visibility impacts of the existing facility. EPA computer software for visibility impacts analyses, intended to predict distant impacts, terminates prematurely when attempts are made to determine close-in impacts. It is concluded that there will be minimal impairment of visibility resulting from the facility's emissions. Given the limitation of 20% opacity of emissions, and a reasonable expectation that normal operation will result in 0% opacity, no local visibility impairment is anticipated.

G. Class I Area Impact Analysis

A further requirement of PSD includes the special protection of air quality and air quality related values (AQRV) at potentially affected nearby Class I areas. Assessment of the potential impact to visibility (regional haze analysis) is required if the source is located within 100 km of a Class I area. The Refinery is not within 100 km of the nearest Class I area, which is the Wichita Mountains Natural Wildlife Refuge (WMNWR). The Refinery is approximately 143 km from the WMNWR. Therefore, the Refinery was not evaluated for its impacts on the WMNWR.

SECTION VII. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]

Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]

Primary Standards are in Appendix E and Secondary Standards are in Appendix F of the Air Pollution Control Rules. At this time, all of Oklahoma is in attainment of these standards.

OAC 252:100-4 (New Source Performance Standards) [Applicable]

Federal regulations in 40 CFR Part 60 are incorporated by reference as they exist on July 1, 2001, except for the following: Subpart A (Sections 60.4, 60.9, 60.10, and 60.16), Subpart B, Subpart C, Subpart Ca, Subpart Cb, Subpart Cc, Subpart Cd, Subpart Ce, Subpart AAA, and Appendix G. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-5 (Registration of Air Contaminant Sources) [Applicable]

Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants. Emission inventories have been submitted and fees paid for the past years.

OAC 252:100-7 (Permits for Minor Facilities) [Not Applicable]

Subchapter 7 sets forth the permit application fees and the basic substantive requirements of permits for minor facilities. However, Subchapter 7 previously contained the requirements for construction and operation of major sources also. If any specific conditions of any previous permit are in conflict with this permit, the specific conditions of this permit will supercede the specific conditions of the previously issued permit.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]

Part 5 includes the general administrative requirements for part 70 permits. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and which exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities mean individual EU that either are on the list in Appendix I (OAC 252:100) or whose actual calendar year emissions do not exceed the following limits:

- 5 TPY of any one criteria pollutant
- 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAPs or 20% of any threshold less than 10 TPY for single HAP that the EPA may establish by rule
- 0.6 TPY of any one Category A toxic substance
- 1.2 TPY of any one Category B toxic substance
- 6.0 TPY of any one Category C toxic substance

Emission and operating limitations have been established based on information in the permit application.

OAC 252:100-9 (Excess Emission Reporting Requirements) [Applicable]

In the event of any release which results in excess emissions, the owner or operator of such facility shall notify the Air Quality Division as soon as the owner or operator of the facility has knowledge of such emissions, but no later than 4:30 p.m. the next working day following the malfunction or release. Within ten (10) working days after the immediate notice is given, the owner operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility. Part 70/Title V sources must report any exceedance that poses an imminent and substantial danger to public health, safety, or the environment as soon as is practicable. Under no circumstances shall notification be more than 24 hours after the exceedance.

OAC 252:100-13 (Prohibition of Open Burning) [Applicable]

Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-17 (Incinerators)

[Not Applicable]

This subchapter specifies design and operating requirements and emission limitations for incinerators, municipal waste combustors, and hospital, medical, and infectious waste incinerators. Thermal oxidizers, flares, and any other air pollution control devices are exempt from this subchapter. The refinery does not have any incinerators besides the control devices used at the refinery.

OAC 252:100-19 (Particulate Matter)

[Applicable]

This subchapter specifies a particulate matter (PM) emission limitation of 0.6 lb/MMBTU from fuel-burning units with a rated heat input of 10 MMBTUH or less. All of the small (<10 MMBTUH) fuel-burning units are fired with refinery fuel-gas or low-sulfur diesel fuel.

Fuel-burning equipment with a rated heat input between 10 and 1,000 MMBTUH are limited to between 0.599 and 0.20 lb/MMBTU as defined in Appendix C. The following table lists all fuel-burning equipment greater than 10 MMBTUH affected by this permit and their associated emission limits.

EU	Type of Unit	MMBTUH	SC 19 Limit (lb/MMBTU)
H-210001	Process Heater	12.0	0.576
H-100024	Asphalt Tank Heater	13.5	0.560
H-402A	Process Heater	13.8	0.558
H-402B	Process Heater	15.9	0.539
H-401A	Process Heater	16.0	0.538
H-401B	Process Heater	17.0	0.531
H-407	Process Heater	25.0	0.484
H-411	Process Heater	28.0	0.471
H-406	Process Heater	28.0	0.471
H-404	Process Heater	48.0	0.414
H-405	Process Heater	50.3	0.410
B-803	Boiler	75.9	0.371
B-802	Boiler	77.8	0.369
B-252	CO Boiler (Existing)	92.0	0.355
H-403	Process Heater	98.7	0.349
H-201	Process Heater	104.7	0.344
B-253	CO Boiler (New)	125.8	0.329
H-102B	Process Heater	135.0	0.324
H-102A	Process Heater	145.0	0.318
H-15001	Process Heater	293.3	0.269

AP-42 (9/98), Chapter 1.3, Table 1.3-2, lists the total PM emissions for distillate fuel oil to be 1.3 lb/10³ gallons or about 0.0093 lb/MMBTU. AP-42 (7/98), Section 1.4, Table 1.4-2, lists the total PM emissions for natural gas to be 7.6 lb/MMft³ or about 0.0076 lb/MMBTU. AP-42 (10/96), Section 3.3, Table 3.3-1, lists the total PM emissions from diesel-fired internal combustion engines less than 600-hp to be 0.31 lb/MMBTU. AP-42 (10/96), Section 3.4, Table

3.4-1, lists the total PM emissions from diesel-fired internal combustion engines greater than 600-hp to be 0.1 lb/MMBTU. The permit requires the use of refinery fuel gas or distillate fuel oil to ensure compliance with Subchapter 19. Since all of the emission limits under Subchapter 19 are greater than the expected emissions from these units, having the permit require these units to only be fueled with refinery fuel gas or distillate fuel oil will ensure compliance with Subchapter 19.

Fuel-burning unit is defined as “any internal combustion engine or gas turbine or any other combustion device used to convert the combustion of fuel into usable energy.” Since flares and incinerators are pollution control devices designed to destroy pollutants and are not used to convert fuel into usable energy, they do not meet the definition of fuel-burning unit and are not subject to these requirements. Also, since the FCCU regenerators and the CCR do not convert combustion of fuel into usable energy, except for the CO boiler, they are not considered fuel-burning units.

This subchapter also limits emissions of PM from directly fired fuel-burning units and industrial processes based on their process weight rates. For process rates up to 60,000 lb/hr (30 TPH), the emission rate in pounds per hour (E) is not to exceed the rate calculated using the process weight rate in tons per hour (P) and the formula in appendix G ($E = 4.10 \cdot P^{(0.67)}$). For process rates greater than 60,000 lb/hr (30 TPH), the emission rate in pounds per hour (E) is not to exceed the rate calculated using the process weight rate in tons per hour (P) and the formula in appendix G ($E = 55.0 \cdot P^{(0.11)} - 40$). Listed in the following table are the process weight rates for the EUs affected by this permit, the estimated emissions, and the allowable emission limits. Emission limits established by Subchapter 19 include the front-half and back-half of the PM sampling train. Therefore, representative emissions from these emission units include the anticipated emissions from both the front-half and the back-half of the sampling train and are greater than the limits that will be established in the permit.

EU	Source	Rate (TPH)	SC 19 Limit (lb/hr)	Emissions (lb/hr)
HI-801	Asphalt Blowstill & TO	10.64	19.99	0.46
WGS-200	FCCU Regenerators*	1,443	82.43	50.44
cat_hop	FCCU Catalyst Hopper Vent	700	73.06	1.88
CCR	Platformer CCR Vent	0.35	2.03	0.39

* - Based only on the catalyst recirculation rate.

The asphalt blowstill incinerator only combusts waste gases and no specific requirements are needed to ensure compliance with this subchapter. The FCCU Regenerators and Catalyst Hopper will be vented to a WS. The permittee will be required to monitor and record the WS operating parameters as shown in the BACT analysis. PM emissions from the Platformer CCR are also controlled using a series of internal screens and cyclones. Since the catalyst is so expensive, every effort is made to recover it and minimize air emissions. There are currently no indirect operating parameters that can be measured to ensure operation of the screens and cyclones.

OAC 252:100-25 (Visible Emissions and Particulate Matter) [Applicable]

No discharge of greater than 20% opacity is allowed except for short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case, shall the average of any six-minute period exceed 60% opacity. EUs subject to an opacity limit under NSPS are exempt from the requirements of this subchapter. When burning refinery fuel-gas in the combustion units (process heaters and boilers) there is little possibility of exceeding the opacity standards. The FCCU is subject to an opacity limit under NSPS, Subpart J. The Asphalt Blowstill is subject to this subchapter. For the blowstill and diesel-fired engines (except for small engines used only during emergencies), the permit will require a daily observation of each stack and opacity readings to be conducted if visible emissions are detected.

OAC 252:100-29 (Fugitive Dust) [Applicable]

No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. Under normal operating conditions, this facility will not cause a problem in this area, therefore it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) [Applicable]

Part 2 limits the ambient air impact of sulfur dioxide (SO₂) emissions from any one existing source or any one new petroleum and natural gas process source subject to OAC 252:100-31-26(a)(1). This part also limits the impact of hydrogen sulfide (H₂S) emissions from any new or existing source. Emissions from all of the equipment have been modeled using ISCST3 and have been shown to be in compliance with these standards as shown in the following tables.

Ambient Impacts of SO₂ (Preliminary Analysis)

Averaging Time	Standard µg/m ³	Impact µg/m ³
5-Minute*	1,300	153
1-hour*	1,200	93
3-hour	650	84
24-hour	130	10

* - Based on the PSD modeling preliminary analysis and adjustment factors for different averaging periods.

Ambient Impacts of H₂S (TV Application)

Averaging Time	Standard µg/m ³	Impact µg/m ³
24-hour	278	22

Part 5 limits sulfur dioxide emissions from new fuel-burning equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lb/MMBTU heat input. This is equivalent to approximately 0.2 weight percent sulfur in the fuel gas which is equivalent to 2,000 ppm sulfur.

All fuel-burning equipment constructed or modified after June 11, 1973, which combust refinery fuel gas are subject to NSPS, Subpart J, which limits the amount of H₂S in the fuel gas to 0.1 grains/DSCF or approximately 160 ppm. The refinery fuel gas has a HHV of approximately 800 BTU/SCF, which is equivalent to approximately 0.0357 lb/MMBTU. Other refinery fuel gas combustion devices, built prior to June 11, 1973, also utilize the same fuel and will be in compliance with the gaseous fuel limit of 0.2 lb/MMBTU.

For liquid fuels the limit is 0.8 lb/MMBTU. All liquid fuels combusted at the facility are low-sulfur fuel oil with a maximum sulfur content of 0.5 percent. AP-42 (9/98), Chapter 1.3, Table 1.3-1, gives an emission factor of 142*S pound of SO₂ per 1,000 gallons which is approximately 0.5 lb/MMBTU when S = 0.5% by weight sulfur in the fuel oil. This emission rate is in compliance with the limitation of 0.8 lb/MMBTU. The permit will require the use of refinery fuel gas with a limit of 160 ppm or fuel oil with a maximum sulfur content of 0.5 % sulfur by weight.

Part 5 also requires new fuel-burning equipment with a heat input greater than 250 MMBTUH to meet other continuous monitoring requirements. There is only one heater (H-15001) that is rated greater than 250 MMTBUH (293 MMBTUH). However, this heater is fired with refinery fuel gas with a maximum H₂S content of 160 ppm, which exempts it from these requirements.

OAC 252:100-33 (Nitrogen Oxides)

[Not Applicable]

NO_x emissions are limited to 0.20 lb/MMBTU from all gas-fired fuel-burning equipment constructed after February 2, 1972, with a rated heat input of 50 MMBTUH or greater. All of the equipment rated greater than 50 MMBTUH and their applicability are listed in the following table.

EU	Name	Rating MMBTUH	Emissions (lb/hr)	Emissions (lb/MMBTU)
H-405	Process Heater	50.3	4.93	0.098
B-803	Boiler	75.9	7.44	0.098
B-802	Boiler	77.8	7.63	0.098
B-252	CO Boiler (Existing)	92.0	2.76	0.030
H-403	Process Heater	98.7	9.68	0.098
H-201	Process Heater	104.7	13.70	0.186
B-253	CO Boiler (New)	125.8	3.77	0.030
H-102B	Process Heater	135.0	6.53	0.048
H-102A	Process Heater	145.0	7.97	0.055
H-15001	Process Heater	293.3	10.85	0.037

The heaters and CO Boilers are equipped with LNB or ULNB. All emissions from the heaters and CO Boilers are in compliance with this subchapter. The FCCU regenerators, CCR, and incinerators do not meet the definition of fuel-burning equipment and are not subject to this subchapter.

OAC 252:100-35 (Carbon Monoxide)

[Applicable]

Subchapter 35 requires new petroleum catalytic cracking and petroleum reforming units to reduce CO emissions by use of complete secondary combustion of the waste gas generated. Removal of 93 percent or more of the carbon monoxide generated is considered equivalent to secondary combustion. The FCCU Regenerators are subject to this subchapter. The FCCU No. 1 Regenerator reduces CO emissions by secondary combustion in the existing CO Boiler and Incinerator or in the new CO Boiler. The FCCU No. 2 Regenerator is a full burn unit with CO emissions at the detection limit. The FCCU No. 2 Regenerator combust the remaining coke from the catalyst that was not combusted in the FCCU No. 1 Regenerator. This secondary combustion, using high temperature regeneration, of the coke on the catalyst is designed to reduce CO emissions. Since the secondary combustion of the coke reduces emission of CO by at least 93% compared to the primary regenerator it is considered equivalent to secondary combustion of the waste gas generated from the FCCU. The Platformer CCR is considered a petroleum catalytic reforming unit and is subject to this subchapter. The permit will require compliance with all applicable requirements of this subchapter.

OAC 252:100-37 (Volatile Organic Compounds)

[Applicable]

Part 1 requires all vapor-loss control devices, packing glands, and mechanical seals required by this subchapter to be properly installed, maintained, and operated.

Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. Part 3 also requires storage tanks constructed after December 28, 1974, with a capacity of more than 40,000 gallons and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with either an external floating roof, a fixed roof with an internal floating cover, a vapor recovery system, or other equally effective control methods approved by the DEQ. Tanks subject to the equipment standards of NSPS, Subparts K, Ka, or Kb are exempt from these requirements. This permit only addresses one tank T-83001 the sour water stripper tank, which is subject to the recordkeeping requirements of NSPS, Subpart Kb. Since the tank does not store a VOC with a vapor pressure greater than 1.5 psia under actual storage conditions it is exempt from this subchapter.

Part 3 applies to VOC loading facilities constructed after December 24, 1974. Facilities with a throughput greater than 40,000 gallons/day are required to be equipped with a vapor-collection and disposal system unless all loading is accomplished by bottom loading with the hatches of the tank truck or trailer closed. Loading facilities subject to the requirements of NSPS, Subpart XX or NESHAP, Subpart R are exempt from these requirements. The light products loading terminal at the refinery is equipped with a vapor-collection and disposal system. This terminal is also subject to NESHAP, Subpart R and is exempt from these requirements.

Part 5 limits the VOC content of coatings used in coating operations or lines. This facility does not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is exempt.

Part 7 requires all VOC gases from a vapor recovery blowdown system to be burned by a smokeless flare or equally effective control device unless it is inconsistent with the "Minimum Federal Safety Standards for the Transportation of Natural and Other Gas by Pipeline" or any State of Oklahoma regulatory agency. This facility flares all emissions that are not processed by a vapor recovery system.

Part 7 requires fuel-burning and refuse-burning equipment to be operated and maintained so as to minimize emissions of VOCs. Temperature and available air must be sufficient to provide essentially complete combustion. All equipment at the refinery is operated to minimize emissions of VOC.

Part 7 also requires all reciprocating pumps and compressors handling VOCs to be equipped with packing glands that are properly installed and maintained in good working order and rotating pumps and compressors handling VOCs to be equipped with mechanical seals. Equipment subject to NSPS, Subpart VV and/or Subpart GGG are exempt from these requirements. The equipment affected by this permit at the refinery is subject to the requirements of NSPS, Subpart GGG.

OAC 252:100-41 (Hazardous and Toxic Air Contaminants) [Applicable]

Part 3 addresses hazardous air contaminants. NESHAP, as found in 40 CFR Part 61, are adopted by reference as they exist on July 1, 2001, with the exception of Subparts B, H, I, K, Q, R, T, W and Appendices D and E, all of which address radionuclides. In addition, General Provisions as found in 40 CFR Part 63, Subpart A, and the Maximum Achievable Control Technology (MACT) standards as found in 40 CFR Part 63, Subparts F, G, H, I, L, M, N, O, Q, R, S, T, U, W, X, Y, CC, DD, EE, GG, HH, II, JJ, KK, LL, MM, OO, PP, QQ, RR, SS, TT, UU, VV, WW, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, RRR, TTT, VVV, XXX, CCCC, and GGGG are hereby adopted by reference as they exist on July 1, 2001. These standards apply to both existing and new sources of HAPs. These requirements are covered in the "Federal Regulations" section.

Part 5 is a **state-only** requirement governing toxic air contaminants. New sources (constructed after March 9, 1987) emitting any category "A" pollutant above de minimis levels must perform a BACT analysis, and if necessary, install BACT. All sources are required to demonstrate that emissions of any toxic air contaminant that exceeds the de minimis level do not cause or contribute to a violation of the MAAC.

The internal combustion engines, boilers, and heaters will have some emissions of air toxics, the most significant being formaldehyde, a Category A air toxic with de minimis levels of 0.57 lb/hr, and 0.6 TPY and a MAAC of 12 $\mu\text{g}/\text{m}^3$, 24-hour basis. However, because there are no reliable emission factors for this pollutant, no estimate of emissions or requirements are listed in this permit. Air Quality reserves the right to reopen the permit if better information becomes available.

OAC 252:100-43 (Sampling and Testing Methods) [Applicable]

All required testing must be conducted by methods approved by the Executive Director under the direction of qualified personnel. All required tests shall be made and the results calculated in accordance with test procedures described or referenced in the permit and approved by Air Quality.

OAC 252:100-45 (Monitoring of Emissions) [Applicable]

Records and reports as Air Quality shall prescribe on air contaminants or fuel shall be recorded, compiled, and submitted as specified in the permit.

The following Oklahoma Air Quality Rules are not applicable to this facility:

OAC 252:100-7	Permit for Minor Facilities	not in source category
OAC 252:100-11	Alternative Emissions Reduction	not requested
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Grain Elevators	not in source category
OAC 252:100-39	Nonattainment Areas	not in area category
OAC 252:100-47	Existing Municipal Solid Waste Landfills	not in source category

SECTION VIII. FEDERAL REGULATIONS

PSD, 40 CFR Part 52

[Applicable]

Total potential emissions for NO_x, CO, VOCs, SO₂, and PM₁₀ are greater than the level of significance of 250 TPY. Modifications of the facility exceeded the significance levels as discussed in the "Emissions" section. The PSD requirements for these modifications are addressed in the "PSD Review" section. Any future increases of emissions must be evaluated for PSD if they exceed a significance level.

NSPS, 40 CFR Part 60

[Subparts Db, Dc, J, Kb, GGG, and QQQ are Applicable]

Subparts D and Da, Fossil Fired Steam Generators. These subparts affect any fossil-fuel-fired steam generating unit with a heat input rate of 250 MMBTUH. Only one EU affected by this permit exceeds 250 MMBTUH and it is not used to generate steam.

EU	Description	MMBTUH	Const. Date
H-15001	Process Heater	293.3	1992

Subpart Db, Industrial-Commercial-Institutional Steam Generating Units. This subpart affects steam generating units with a heat input capacity greater than 100 MMBTUH and that commenced construction, modification, or reconstruction after June 19, 1984. All of the units greater than 100 MMBTUH affected by this permit meet the definition of process heaters and are not affected units. Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst. Except for the new CO Boiler, the EU listed below either heat the crude oil entering the refinery or heat the FCCU feedstock. The new CO boiler is subject to this subpart.

EU	Description	MMBTUH	Const. Date
H-102A	Process Heater	145.0	Mod. 1990
H-102B	Process Heater	135.0	Mod. 1990
B-253	CO boiler (New)	125.8	2002-3
H-201	Process Heater	104.7	1974

Subpart Dc, Small Industrial-Commercial-Institutional Steam Generating Units. This subpart affects steam generating units with a heat input capacity between 10 and 100 MMBTUH and that commences construction, modification, or reconstruction after June 9, 1989. Process heaters are not affected units. Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst. EU H-403, H-404, H-405, H-406, H-401A, H-401B, H-402A, H-402B, H-407, and H-411 all heat a material to initiate or promote a chemical reaction of which the heated material participates as a reactant. The remaining EU are considered steam generating units. Steam generating unit means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. EU H-100024 and H-210001 heat oil, which is then used to transfer heat to other materials, and are subject to this subpart. EU B-252 and B-253 produce steam from the combustion of refinery fuel gas and the FCCU Regenerator No. 1 off-gases. EU B-802, B-803, and B-252 were constructed prior to the applicability date of this subpart. The new CO boiler will be subject to this subchapter.

EU	Description	MMBTUH	Const. Date
H-210001	Process Heater	12.0	1996
H-100024	Asphalt Tank Heater	13.5	1999
H-402A	Process Heater	13.8	< 1968
H-402B	Process Heater	15.9	< 1968
H-401A	Process Heater	16.0	< 1968
H-401B	Process Heater	17.0	1974
H-407	Process Heater	25.0	1974
H-411	Process Heater	28.0	1985
H-406	Process Heater	28.0	1974
H-404	Process Heater	48.0	Mod. 1995
H-405	Process Heater	50.3	Mod. 1995
B-803	Boiler	75.9	1975
B-802	Boiler	77.8	1975
B-252	CO Boiler	92.0	1984
H-403	Process Heater	98.7	1975

Heaters H-210001 and H-100024 and the existing CO boiler are subject to the fuel recordkeeping requirement of this subpart since they do not combust coal, wood, oil and/or a mixture of these fuels. Heaters H-210001 and H-100024 only combust refinery fuel-gas and the existing CO boiler combusts refinery fuel-gas and off-gases from the FCCU No. 1 Regenerator. Per 40 CFR 60.48(g) the owner/operator of each affected EU will be required to record and maintain records of the amounts of each fuel combusted during each day.

Subpart I, Hot Mix Asphalt Facilities. This facility does not manufacture hot mix asphalt by heating and drying aggregate and mixing with asphalt cements. This facility only manufactures asphalt cements.

Subpart J, Petroleum Refineries. This subpart applies to the following affected facilities in petroleum refineries: FCCU catalyst regenerators, fuel gas combustion devices, and Claus sulfur recovery plants. This permit will not address any Claus sulfur recovery plants. All fuel gas combustion devices which commence construction or modification after June 11, 1973, are subject to a fuel gas H₂S limitation of 0.10 grains of H₂S/DSCF which is required to be continuously monitored and recorded. Fuel gas does not include gases generated by catalytic cracking unit catalyst regenerators. All of the refinery fuel gas combustion devices listed below are subject to this subpart. The CO boilers are affected units but only due to the supplemental fuel gas they combust. The FCCU regenerator off-gases are not fuel gas. Fuel gas combusted by the affected units must be monitored and recorded and can be done at one location. Based on 1998 monitoring data, the typical sulfur content of the refinery fuel gas used at the Valero Refinery is 0.027 grains of H₂S/DSCF. All emission limits, monitoring, and recordkeeping requirements for the refinery fuel gas combustion devices will be incorporated into the permit.

EU	Type of Unit	MMBTUH	Const. Date
crude unit flare	Process Flare	N/A	1976
HI-801	Asphalt Blowstill and Thermal Oxidizer	N/A	1992
HI-81001	Platformer and Alkylation Units	N/A	1993
Light Products Loading Terminal	Gasoline Loading Rack Vapor Combustor	N/A	1996
H-210001	Process Heater	12.0	1996
H-100024	Asphalt Tank Heater	13.5	1999
H-401B	Process Heater	17.0	1974
H-407	Process Heater	25.0	1974
H-411	Process Heater	28.0	1985
H-406	Process Heater	28.0	1974
H-404	Process Heater	48.0	Mod. 1995
H-405	Process Heater	50.3	Mod. 1995
B-803	Boiler	75.9	1975
B-802	Boiler	77.8	1975
B-252	CO Boiler	92.0	1984
B-253	CO Boiler	125.8	2002-3
H-403	Process Heater	98.7	1975
H-201	Process Heater	104.7	1974
H-102B	Process Heater	135.0	Mod. 1990
H-102B	Process Heater	135.0	Mod. 1990
H-102A	Process Heater	145.0	Mod. 1990
H-15001	Process Heater	293.3	1992

All FCCU catalyst regenerators that commence construction or modification after June 11, 1973, are subject to the following limitations:

- 1) A PM emission limitation of 1.0 lb/1,000 lbs of coke burn-off, which is required to be continuously monitored and recorded (when exhaust gases discharged from the FCCU are combusted by a waste heat boiler in which supplemental liquid or solid fuel is burned PM in excess of this limit may be emitted which shall not exceed 0.1 lb/MMBTU of heat input);
- 2) A 30% opacity limitation, except for one six-minute average opacity reading in any one hour period;
- 3) A CO emission limitation of 500 ppm by volume on a dry basis, which is required to be continuously monitored and recorded; and
- 4) One of the following SO₂ emission limitations:
 - a) For units with an add-on control device, a requirement to reduce SO₂ emissions by 90% or to maintain SO₂ emissions to less than 50 ppmv, whichever is less stringent; or
 - b) For units without an add-on control device, an SO₂ emission limitation of 9.8 lbs/1,000 lbs of coke burn-off; or
 - c) A limit of the 0.30 percent by weight or less sulfur in the FCCU fresh feed.Compliance with these limits must be determined based continuous monitoring and a seven day rolling average.

FCCU catalyst regenerators that commenced construction or modification prior to January 17, 1984, are exempt from the SO₂ emission limit. The FCCU was modified after 1984 and is subject to this entire subpart. The Platformer CCR is considered a catalytic reforming unit and is not subject to this subpart. The permit will require the permittee to comply with all applicable requirements of the subpart.

Subpart K, Storage Vessels for Petroleum Liquids. This subpart affects storage vessels for petroleum liquids which have a storage capacity greater than 40,000 gallons but less than 65,000 gallons and which commenced construction, reconstruction, or modification after March 8, 1974, or which have a capacity greater than 65,000 gallons which commenced construction, reconstruction, or modification after June 11, 1973, and prior to May 19, 1978. The only tank affected by this permit (T-83001) was constructed after the effective dates of this subpart.

Subpart Ka, Storage Vessels for Petroleum Liquids. This subpart affects storage vessels for petroleum liquids that have a storage capacity greater than 40,000 gallons and which commenced construction, reconstruction, or modification after May 18, 1978, and prior to July 23, 1984. The only tank affected by this permit (T-83001) was constructed after the effective dates of this subpart.

Subpart Kb, VOL Storage Vessels. This subpart affects storage vessels for volatile organic liquids (VOLs) which have a storage capacity greater than or equal to 10,567 gallons and which commenced construction, reconstruction, or modification after July 23, 1984. The tank is subject to the recordkeeping requirements of this subpart.

EU	Roof Type	Contents	Barrels	Const. Date
T-83001	Cone	Sour Water	18,500	1993

Tanks with a capacity of less than 19,813 gallons are only required to keep records of the dimension and capacity of the vessels. Tanks with a capacity of less than 39,890 gallons and which store a VOL with a maximum true vapor pressure of less than 2.175 psia and tanks with a capacity equal to or greater than 39,890 gallons which store a VOL with a maximum true vapor pressure of less than 0.5 psia are required to keep records of the VOL stored and the maximum true vapor pressure of the VOL.

Tank T-83001 has a capacity that is greater than 39,890 gallons. All required recordkeeping and equipment standards will be incorporated into the permit.

Subpart GG, Stationary Gas Turbines. There are no turbines located at this facility.

Subpart UU, Asphalt Processing and Asphalt Roofing Manufacture. This subpart affects each asphalt storage tank and each blowing still at petroleum refineries. Asphalt storage tanks and blowing stills that process and/or store asphalt used for roofing and other purposes and that commenced construction or modification after November 18, 1980, are subject to the requirements of this subpart. Asphalt storage tanks and blowing stills that process and/or store only non-roofing asphalt and that commenced construction or modification after May 26, 1981, are also subject to the requirements of this subpart. The Asphalt Blowstill was altered in 1992. However, since only the blowstill thermal oxidizer was replaced and no increase in emissions resulted from the project, the modification was not considered a modification under NSPS. Therefore, the Asphalt Blowstill is not subject to the requirements of this subpart.

EU	Point	Description	Const. Date
HI-801	P-117	Asphalt Blowstill and Thermal Oxidizer	Mod. 1992

Subpart VV, Equipment Leaks of VOC in the Synthetic Organic Manufacturing Industry. NSPS, Subpart GGG requires equipment in VOC service to comply with paragraphs §§ 60.482-1 through 60.482-10, 60.484, 60.485, 60.486, and 60.487 except as provided in § 60.593. All equipment affected under this permit are subject to NSPS, Subpart GGG.

Subpart XX, Bulk Gasoline Terminals. This subpart affects loading racks at a bulk gasoline terminals which deliver liquid product into gasoline tank trucks and that commenced construction or modification after December 17, 1980. The gasoline terminal at the refinery was built prior to the applicable effective date of this subpart and was later modified to comply with NESHAP, Subpart CC.

Subpart DDD, VOC Emissions from the Polymer Manufacturing Industry. This subpart affects facilities that manufacture polyethylene, polypropylene, polystyrene, and polyethylene terephthalate. This facility does not manufacture any of these compounds.

Subpart GGG, Equipment Leaks of VOC in Petroleum Refineries. This subpart affects each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service at a process unit that commenced construction or modification after January 4, 1983, and which is located at a petroleum refinery. The permit will require all affected equipment to comply with the applicable requirements of NSPS, Subparts GGG and VV. The permittee has elected to comply with the alternative standard for valves §§ 483-1 and 483-2.

Subpart III, VOC Emissions from SOCM I Air Oxidation Unit Processes. This subpart affects facilities with air oxidation reactors that produce, as a product, co-product, by-product, or intermediate, any of the chemicals listed in § 60.617. The Asphalt Blowstill is the only air oxidation process at the facility and it does not produce a listed chemical.

Subpart KKK, Equipment Leaks of VOC from Onshore Natural Gas Processing Plants. This subpart sets standards for natural gas processing plants which are defined as any site engaged in the extraction of natural gas liquids from field gas, fractionation of natural gas liquids, or both. This facility does not extract natural gas liquids from field gas or fractionate natural gas liquids.

Subpart LLL, Onshore Natural Gas Processing: SO₂ Emissions. This subpart affects each sweetening unit and each sweetening unit followed by a sulfur recovery unit that process natural gas which commenced construction or modification after January 20, 1984. Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface. This facility only processes gases that are generated at the facility from the processing of crude oil.

Subpart NNN, VOC Emissions from SOCM I Distillation Operations. This subpart affects facilities that are a part of a process unit that produce, as a product, co-product, by-product, or intermediate, any of the chemicals listed in § 60.667. This facility produces listed chemicals and uses distillation to separate the desired product. However, none of the distillation and recovery process streams are vented to the atmosphere.

Subpart OOO, Nonmetallic Mineral Processing Plants. This subpart affects each crusher, grinding mill, screening operation, bucket elevator, belt conveyor, bagging operation, storage bin, enclosed truck or railcar loading station at nonmetallic mineral processing plants. This facility does not crush or grind any nonmetallic minerals.

Subpart QQQ, VOC Emission from Petroleum Refinery Wastewater Systems. This subpart applies to individual drain systems, oil-water separators, and aggregate facilities located in a petroleum refinery and which commenced construction, modification, or reconstruction after May 4, 1987. Drains are required to be equipped with water seal controls. Junction boxes are required to be equipped with a cover and may have an open vent pipe. Sewer lines shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces. Oil-water wastewater separators shall be equipped with a fixed roof, which meets the required specifications. All required recordkeeping and equipment standards will be incorporated into the permit. Group 1 wastewater streams that

are managed under this subpart that are also subject to the provisions of NESHAP, Subpart CC are only required to comply with Subpart CC.

Subpart RRR, VOC Emissions from SOCMR Reactor Processes. This subpart affects facilities that are a part of a process unit that produce, as a product, co-product, by-product, or intermediate, any of the chemicals listed in § 60.707. This facility produces listed chemicals and has a reactor to produce the desired products. However, all streams from the reactors are recovered. There are no vent stream to control.

NESHAP, 40 CFR Part 61

[Applicable]

Subpart J, Equipment Leaks(Fugitive Emission Sources) of Benzene. This subpart affects process streams that contain more than 10% benzene by weight. The maximum benzene concentration in any product stream at this site is 5% in super unleaded gasoline, and only trace amounts are expected in the refinery fuel gas.

Subpart FF, Benzene Waste Operations. This subpart affects benzene-contaminated wastewater at petroleum refineries. Facilities with less than 1-10 metric tons of benzene from facility waste are required to conduct annual determinations of the total annual benzene quantity from facility wastes. NESHAP, Part 63, Subpart CC requires all Group 1 wastewater streams to comply with §§ 61.340 through 61.355 of 40 CFR Part 61, Subpart FF for each process wastewater stream that meets the definition in § 63.641. All required monitoring, and recordkeeping requirements will be incorporated into the permit.

NESHAP, 40 CFR Part 63

[Subparts R and CC are Applicable]

Subpart G, Organic Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater. Subpart CC requires all Group 1 storage vessels to comply with §§ 63.119 through 63.121 of Subpart G. There is no Group 1 storage vessels affected by this permit.

Subpart Q, Industrial Cooling Towers. This subpart applies to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals on or after September 8, 1994, and are either major sources or are integral parts of facilities that are major sources as defined in § 63.401. This facility does not have or use industrial process cooling towers that are operated with chromium-based water treatment chemicals.

Subpart R, Gasoline Distribution Facilities. Bulk gasoline terminals or pipeline breakout stations with a Standard Industrial Classification code 2911 located within a contiguous area and under common control with a refinery complying with Subpart CC, §§ 63.646, 63.648, 63.649, and 63.650 are not subject to this subpart, except as specified in Subpart CC, § 63.650. Subpart CC, § 63.650(a) requires all facilities to comply with Subpart R, §§ 63.421, 63.422 (a) through (c), 63.425 (a) through (c), 63.425 (e) through (h), 63.427 (a) and (b), and 63.428 (b), (c), (g)(1), and (h)(1) through (h)(3). Subpart CC § 63.650(b) states that all terms not defined in § 63.641 shall have the meaning given them in Subpart A or in 40 CFR part 63, Subpart R and that the definition of “affected source” in § 63.641 applies under this section. § 63.650(c) requires all gasoline loading racks regulated under Subpart CC to comply with the compliance dates

specified in § 63.640(h). All applicable requirements of this subpart, as per Subpart CC, are incorporated into the permit.

Subpart CC, Petroleum Refineries. This subpart, promulgated on August 18, 1995, affects various process units and related emission points at petroleum refineries. The affected emission points are listed below with a summary of the applicable requirements. EU affected by this permit are shown in their respective sections.

Miscellaneous process vents from petroleum refining process units

Group 1 miscellaneous process vents must reduce emissions of organic HAPs using a flare or a control device which reduces emissions by 98 % weight or to a concentration of 20 ppmv. Group 1 miscellaneous process vents are vents associated with petroleum process refining units that contain greater than 20 ppmv organic HAPs and approximately 73 lb/day of VOCs at an existing source or 15 lb/day at a new source prior to control. There are no Group 1 miscellaneous process vents affected by this permit.

Storage vessels associated with petroleum refining process units, bulk gasoline terminals, or pipeline breakout stations

Group 1 storage vessels are required to comply with §§ 63.119 through 63.121 of Subpart G except as provided for in § 63.646(b) through (l). Group 1 storage vessels for an existing source are vessels that meet the following requirements:

- A design capacity greater than or equal to 46,758 gallons;
- Store a liquid with a maximum true vapor pressure greater than or equal to 1.5 psia;
- Store a liquid with a annual average true vapor pressure greater than or equal to 1.2 psia; and
- Store a liquid with an annual average HAP concentration greater than 4 percent by weight.

Group 2 storage vessels that are part of an existing source and subject to the provisions of NSPS Subpart Kb are only required to comply with the provisions of NSPS Subpart Kb except as provided in § 63.640(n)(8)(i) through (vi). The only tank affected by this permit (T-83001) is subject to NSPS Subpart Kb.

Wastewater streams and treatment operations associated with petroleum refining process units

Group 1 wastewater streams are required to comply with §§ 61.340 through 61.355 of 40 CFR Part 61, Subpart FF for each process wastewater stream that meets the definition in § 63.641. Group 1 wastewater streams are petroleum wastewater streams that meet the following requirements:

- A total annual benzene loading of approximately 11 tons per year as calculated in § 61.342;
- A flow rate greater than or equal to 0.317 gallons per hour;
- A benzene concentration of 10 ppm weight or greater; and
- Are not exempt from the control requirements of 40 CFR Part 61, Subpart FF.

Group 1 wastewater streams that are affected by this subpart and that are managed under NSPS, Subpart QQQ are only required to comply with Subpart CC. Any Group 1 wastewater stream affected by this permit will be required to comply with this subpart. All applicable requirements will be incorporated into the permit.

Equipment leaks from petroleum refining process units, bulk gasoline terminals, or pipeline breakout stations

All equipment in organic HAP service is required to comply with the provisions of 40 CFR Part 60, Subpart VV, except as provided in § 63.648(a)(1), (a)(2), and (c) through (i). All equipment subject to NSPS Subpart GGG and this subpart is only required to comply with this subpart. All equipment in organic HPA service will be required to comply with this subpart. All applicable requirements will be incorporated into the permit.

Gasoline loading racks or pipeline breakout stations

Gasoline loading racks are required to comply with Subpart R, §§ 63.421, 63.422 (a) through (c), 63.425 (a) through (c), 63.425 (e) through (h), 63.427 (a) and (b), and 63.428 (b), (c), (g)(1), and (h)(1) through (h)(3). The Light Products Loading Rack is subject to this section and all applicable requirements will be incorporated into this permit.

Marine vessel loading operations

There are no marine vessel loading operations at this facility.

Sulfur plant vents and fuel gas emission points are specifically exempted from this subpart. All applicable emission limits, work practices, monitoring, and recordkeeping requirements of this subpart will be incorporated into the permit.

Subpart UUU, Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units. This subpart, affects the following EUs:

- Catalytic cracking units that regenerate catalyst;
- Catalytic reforming units that regenerate catalyst; and
- Sulfur recovery units and the tail gas treatment unit serving it;
- Each bypass line serving a new, existing, or reconstructed catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit.

All existing affected sources are required to comply with this subpart by April 11, 2005, except as provided by § 63.1563(c). This subpart does not apply to thermal catalytic cracking units or gaseous streams routed to a fuel gas system.

Catalytic cracking units subject to the NSPS, Subpart J, PM emissions limits must comply with the NSPS Subpart J, PM emission limit. Catalytic cracking units subject to the NSPS, Subpart J, CO emissions limits must comply with the NSPS Subpart J, CO emission limit. Catalytic reforming units must comply with one of the organic HAP emission limits of § 63.1566(a)(1)(i) or (ii), the inorganic HAP emission limits of § 63.1567(a)(1)(i) or (ii), and all other applicable requirements. Sulfur recovery units subject to the NSPS, Subpart J, SO₂ emission limits must

comply with the NSPS Subpart J, SO₂ emission limit. Bypass lines must meet the work practice standards in Table 36 of this subpart. The FCCU is subject to NSPS, Subpart J and will meet all applicable requirements of this subpart and NSPS Subpart J. The Platformer CCR is a catalytic reforming unit and will be subject to the new standards of this subpart. There are no sulfur recovery units covered under this permit.

Subpart EEEE, Organic Liquids Distribution (Non-Gasoline). This subpart was proposed on April 2, 2002, and will affect organic liquid distribution (OLD) operations at major sources of HAPs with an organic liquid throughput greater than 7.29 million gallons per year (173,571 barrels/yr). This subpart affects the following EUs at existing facilities:

- Tanks with a capacity $\geq 20,000$ gallons but $< 40,000$ gallons that store an organic liquid that contains $> 5\%$ HAPs and that has an annual average vapor pressure ≥ 1.9 but < 11.1 psia;
- Tanks with a capacity $\geq 40,000$ gallons that store an organic liquid that contains $> 5\%$ HAPs and that has an annual average vapor pressure ≥ 0.75 psia.
- Transfer racks that loads at any position ≥ 11.8 million liters (3.12 million gallons) per year of organic liquids into a combination of tank trucks and railcars.

Sources controlled under another NESHAP are exempt from this subpart. There are no OLD operations affected by this permit.

Subpart LLLLL, Asphalt Processing. This subpart was proposed on April 2, 2002, and will affect asphalt processing plants and asphalt roofing manufacturing line at petroleum refineries or other facility. Asphalt processing facilities include asphalt heating, blowing stills, asphalt flux storage tanks, oxidized asphalt storage tanks, and oxidized asphalt loading racks. The asphalt processing facility at the refinery is expected to be subject to these regulations when they are finalized.

Additionally, there is a schedule for other MACT standards under 40 CFR Part 63 that may affect this facility: “Subpart DDDDD, Industrial, Commercial and Institutional Boilers and Process Heaters,” “Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE),” which were scheduled for promulgation by May 2002. Air Quality reserves the right to reopen this permit if any standard becomes applicable.

CAM, 40 CFR Part 64

[Not Applicable At This Time]

Compliance Assurance Monitoring (CAM), as published in the Federal Register on October 22, 1997, applies to any pollutant specific EU at a major source, that is required to obtain a Title V permit, if it meets all of the following criteria:

- It is subject to an emission limit or standard for an applicable regulated air pollutant;
- It uses a control device to achieve compliance with the applicable emission limit or standard; and
- It has potential emissions, prior to the control device, of the applicable regulated air pollutant greater than major source levels.

EUs subject to an emission limit or standard proposed after November 15, 1990 are exempt from the CAM requirements for that emission limit or standard. EUs subject to an emission limit or standard for which a Part 70 permit specifies a continuous compliance determination method are exempt from the CAM for that emission limit or standard.

None of the EUs meet the criteria stated above except for the Asphalt Blowstill and Thermal Oxidizer (VOC), the Gasoline Loading Rack (VOC), the FCCU WS (SO₂, CO, PM₁₀), and the Platformer CCR (PM₁₀). The Gasoline Loading Rack is subject to NESHAP, Subpart CC and is exempt from this standard. The permit will require the permittee to continuously monitor the SO₂ and CO emissions from the FCCU WS and the WS operational parameters established during initial testing (WGS liquid flow rate and pressure drop) to ensure compliance with the PM₁₀ emission limits. Emissions from the Asphalt Blowstill Thermal Oxidizer and Platformer CCR are below the major source levels after control and do not have to comply with CAM until renewal of their Title V operating permit. However, the permit will require the permittee to monitor and record the operational parameters of the thermal oxidizer (presence of flame on oxidizer) and Platformer CCR to ensure compliance with the established emission limits.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Applicable]

This facility handles naturally occurring hydrocarbon mixtures at a refinery and the Chemical Accident Prevention Provisions are applicable to this facility. The facility was required to submit the appropriate emergency response plan prior to June 21, 1999. The facility has submitted their plan which was given EPA No. 12005 for EPA Facility No. 1000 00128177. More information on this federal program is available on the web page: www.epa.gov/ceppo.

Stratospheric Ozone Protection, 40 CFR Part 82 [Applicable]

This facility does not produce, consume, recycle, import, or export any controlled substances or controlled products as defined in this part, nor does this facility perform service on motor (fleet) vehicles that involves ozone-depleting substances. Therefore, as currently operated, this facility is not subject to these requirements. To the extent that the facility has air-conditioning units that apply, the permit requires compliance with Part 82.

SECTION IX. TIER CLASSIFICATION, PUBLIC REVIEW, AND FEES

A. Tier Classification and Public Review

This application has been determined to be a Tier II based on the request for a construction permit for an existing Part 70 source for a physical change that is considered significant under OAC 252:100-8-7.2(b)(2).

The permittee has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the land used to accomplish the permitted purpose.

The applicant published the "Notice of Filing a Tier II Application" in the *Daily Ardmoreite*, a daily newspaper, in Carter County, on July 10, 2002. The notice stated that the application was available for public review at the Ardmore Public Library located at 320 E. NW, Ardmore, Oklahoma. The applicant published the "Notice of Tier II Draft Permit" in the *Daily Ardmoreite*, a daily newspaper, in Carter County, on October 24, 2002. The notice stated that the draft permit was available for public review at the Ardmore Public Library located at 320 E. NW, Ardmore, Oklahoma, at the AQD Main Office, and on the Air Quality section of the DEQ web page at <http://www.deq.state.ok.us>. This facility is located within 50 miles of the Oklahoma - Texas border. The state of Texas has been notified of the draft permit. No comments were received from the State of Texas, the public, or EPA Region VI.

The applicant has requested three changes to the permit. First, the applicant has requested a restriction on the placement of the emergency air compressor. The applicant wants to limit the placement of the emergency air compressor to the north end of the FCCU area. Secondly, the applicant has requested to limit the fuel for hot oil heater H-210001 to commercial grade natural gas and not refinery fuel gas. Finally, the applicant has requested clarification concerning which parts of the sampling train will be used to show compliance with the established emission limits since both the front-half and the back-half are required to be collected and reported. The BACT analysis only represents the front-half of the PM₁₀ sampling train. Emission limits established by OAC 252:100-19 include the front-half and back-half of the PM sampling train. The Permit Memorandum and the Specific Conditions have been modified to reflect the requested changes. Since the changes are not considered significant, the permit was not required to go through public review again.

B. Fees Paid

Construction permit application fee of \$2,000, which was the fee due for a construction permit application when the original application was submitted in 1998.

SECTION X. SUMMARY

The applicant has demonstrated the ability to comply with all applicable Air Quality rules and regulations. Ambient air quality standards are not threatened at this site. Compliance and Enforcement concur with the issuance of this permit. Issuance of the permit is recommended.

**PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS**

Valero Energy Corporation

TPI Petroleum, Inc.

Valero Ardmore Refinery

Administrative Consent Order No. 02-007

Permit No. 98-172-C (PSD)

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on December 30, 1998, April 21, 2000, and June 10, 2002. The Evaluation Memorandum dated January 10, 2003, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. As required by Administrative Consent Order No. 02-007, effective March 3, 2002 and applicable state and federal regulations, the permittee is authorized to construct, and/or operate, the affected equipment in conformity with the specifications contained herein. Commencing construction, or operations, under this permit constitutes acceptance of, and consent to, the conditions contained herein:

1. Upon issuance of an operating permit, the permittee shall be authorized to operate the affected facilities noted in this permit continuously (24 hours per day, every day of the year) subject to the following conditions: [OAC 252:100-8-6(a)(1)]

- a. The crude unit shall not process fresh feedstock at a rate to exceed 85,000 bbl/day based on a 12-month rolling average.
- b. The fluid catalytic cracking unit (FCCU) shall not process fresh feedstock at a rate to exceed 30,000 bbl/day based on a 12-month rolling average.
- c. The catalytic reforming/platforming unit shall not process fresh feedstock at a rate to exceed 23,000 bbl/day based on a 12-month rolling average.
- d. The asphalt blowstill shall not process fresh feedstock at a rate to exceed 14,000 bbl/day based on a 12-month rolling average.
- e. The polymer modified asphalt (PMA) unit shall not produce PMA at a rate to exceed 3,600,000 bbl/yr based on a 12-month rolling average.

2. Emission limitations and standards for affected Emission Units (EU):

EUG 49 Sour Water Stripper Tank (T-83001). Emission limits for EU T-83001. Emissions from EU T-83001 are based on a throughput of 2,565,500 bbl/yr and operation of the tank with a barrier of diesel fluid at least six inches thick.

EU	Point	Roof Type	Contents	Barrels
T-83001	P-56	Cone	Sour Water	18,500

VOC	
lb/hr	TPY
4.0	6.2

- a. EU T-83001 shall be operated with a barrier of diesel fluid. [OAC 252:100-8-6(a)(1)]
- b. The throughput for EU T-83001 shall not exceed 2,565,500 bbl/yr based on a 12-month rolling average. [OAC 252:100-8-6(a)(1)]
- c. Records of throughput shall be maintained (monthly and 12-month rolling average). [OAC 252:100-8-6(a)(3)]
- d. EU T-83001 is subject to New Source Performance Standards (NSPS), Subpart Kb and shall comply with all applicable provisions. [40 CFR Part 60, Subpart Kb]
 - i. The owner/operator shall keep for the life of the storage vessel readily accessible records showing the dimensions of the storage vessel and an analysis showing the capacity of the storage vessel. [§ 60.116b (a) & (b)]

EUG 101 Process Heater (H-102B). Emission limits and standards for EU H-102B are listed below. Emissions from H-102B are based on a maximum rated capacity (HHV) of 135 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H₂S concentration of 159 ppm_{dv}, except for emissions of NO_x, which are based on an emission factor of 0.059 lb/MMBTU.

EU	Point	Description	MMBTUH
H-102B	P-102	Process Heater	135.0

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
7.97	34.90	11.12	48.70	1.64	7.19	4.52	19.81	0.73	3.19

- a. EU H-102B is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
 - i. § 60.104 Standards for sulfur dioxide – (a)(1)
 - ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
 - iii. § 60.106 Test methods and procedures – (e)
- b. H-102B shall be operated with Ultra Low-NO_x burners (ULNB). [OAC 252:100-8-34]
- c. Emissions of NO_x from EU H-102B shall not exceed 0.059 lb/MMBTU. [OAC 252:100-8-34]
- d. Fuel use (SCF) and heat content (BTU/SCF) for EU H-102B shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]
- e. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above.

EUG 102 Process Heater (H-102A). Emission limits and standards for EU H-102A are listed below. Emissions from H-102A are based on a maximum rated capacity (HHV) of 145 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H₂S concentration of 159 ppm_{dv}, except for emissions of NO_x, which are based on an emission factor of 0.045 lb/MMBTU.

EU	Point	Description	MMBTUH
H-102A	P-103	Process Heater	145.0

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
6.53	28.60	11.94	52.30	1.76	7.72	4.86	21.28	0.78	3.42

- a. EU H-102A is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
 - i. § 60.104 Standards for sulfur dioxide – (a)(1)
 - ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
 - iii. § 60.106 Test methods and procedures – (e)
- b. H-102A shall be operated with ULNB. [OAC 252:100-8-34]
- c. Emissions of NO_x from EU H-102A shall not exceed 0.045 lb/MMBTU. [OAC 252:100-8-34]
- d. Fuel use (SCF) and heat content (BTU/SCF) for EU H-102A shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]
- e. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above.

EUG 103 Process Heater (H-403). Emission limits and standards for EU H-403 are listed below. Emissions from H-403 are based on a maximum rated capacity (HHV) of 98.7 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H₂S concentration of 159 ppm_{dv}.

EU	Point	Description	MMBTUH
H-403	P-104	Process Heater	98.7

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
9.68	42.38	8.13	35.60	0.74	3.22	3.31	14.48	0.53	2.33

- a. EU H-403 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
 - i. § 60.104 Standards for sulfur dioxide – (a)(1)
 - ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
 - iii. § 60.106 Test methods and procedures – (e)

EUG 104 Process Heater (H-404). Emission limits and standards for EU H-404 are listed below. Emissions from H-404 are based on a maximum rated capacity (HHV) of 48.0 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H₂S concentration of 159 ppm_{dv}.

EU	Point	Description	MMBTUH
H-404	P-105	Process Heater	48.0

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
4.71	20.61	3.95	17.31	0.36	1.57	1.61	7.04	0.26	1.13

- a. EU H-404 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
- § 60.104 Standards for sulfur dioxide – (a)(1)
 - § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
 - § 60.106 Test methods and procedures – (e)

EUG 105 Process Heater (H-405). Emission limits and standards for EU H-405 are listed below. Emissions from H-405 are based on a maximum rated capacity (HHV) of 50.3 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H₂S concentration of 159 ppmv.

EU	Point	Description	MMBTUH
H-405	P-106	Process Heater	50.3

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
4.93	21.60	4.14	18.14	0.37	1.64	1.69	7.38	0.27	1.19

- a. EU H-405 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
- § 60.104 Standards for sulfur dioxide – (a)(1)
 - § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
 - § 60.106 Test methods and procedures – (e)

EUG 106 Process Heater (H-406). Emission limits and standards for EU H-406 are listed below. Emissions from H-406 are based on a maximum rated capacity (HHV) of 28.0 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H₂S concentration of 159 ppmv.

EU	Point	Description	MMBTUH
H-406	P-107	Process Heater	28.0

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
2.75	12.02	2.31	10.10	0.21	0.91	0.94	4.11	0.15	0.66

- a. EU H-406 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
- i. § 60.104 Standards for sulfur dioxide – (a)(1)
 - ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
 - iii. § 60.106 Test methods and procedures – (e)

EUG 115 Process Flare (Crude Unit Flare). Emission limits and standards for EU Crude Unit Flare are listed below. Emissions from the Crude Unit Flare are based on a maximum rated capacity (HHV) of 28 MMBTUH, the respective emissions factors from AP-42, Section 13.5 (1/95), and a fuel gas H₂S concentration of 159 ppmv.

EU	Point	Description	MMBTUH
Crude Unit Flare	P-116	Process Flare	28

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1.84	8.04	9.99	43.76	0.25	1.10	0.91	3.97	3.78	16.56

- a. The flare is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
- i. § 60.104 Standards for sulfur dioxide – (a)(1)
 - ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii) or other alternative monitoring approved per § 60.13.
 - iii. § 60.106 Test methods and procedures – (e)
- b. The flare shall comply with all applicable requirements including but not limited to the following requirements: [40 CFR Parts 60 and 63]
- i. The flare shall meet the design requirements of 40 CFR Part 60 NSPS, Subpart A.
 - ii. The flare shall meet the design requirements of 40 CFR Part 63 NESHAP, Subpart A.

EUG 116 Asphalt Blowstill and Thermal Oxidizer (HI-801). Emission limits and standards for EU HI-801 are listed below. Emissions from HI-801 are based on a maximum rated auxiliary fuel flow of 12 MMBTUH (HHV), a waste gas flow rate of 21,287 lb/hr with a heat content of 2,363 BTU/lb and a nitrogen content of 6.2 ppmv, the emissions factors from AP-42, Section 1.4 (7/98) and Section 13.5 (1/95) (whichever gave the highest emissions), and an H₂S concentration of 159 ppmv.

EU	Point	Description
HI-801	P-117	Asphalt Blowstill and Thermal Oxidizer

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
9.36	41.03	23.05	101.0	0.46	2.03	7.98	34.94	8.72	38.20

- a. EU HI-801 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
 - i. § 60.104 Standards for sulfur dioxide – (a)(1)
 - ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii) or other alternative monitoring approved per § 60.13.
 - iii. § 60.106 Test methods and procedures – (e)
- b. All off-gases from the asphalt blowstill shall be combusted by a properly operated and maintained thermal oxidizer.
- c. The temperature of the combustion zone in the Thermal Oxidizer of EU HI-801 shall not drop below 1,100 °F.
- d. The permittee shall monitor and record the temperature of the combustion zone of the Thermal Oxidizer of EU HI-801 (daily).
- e. EU HI-801 shall not process more than 21,287 lb/hr of waste gas as determined by site-specific parametric association of waste-gas generation as a function of asphalt throughput and the air flow rate into the asphalt blowing process.
- f. The permittee shall monitor and record the asphalt throughput of the blowstill (daily).
- g. The permittee shall determine and record the amount of waste gas generated from the asphalt blowstill per barrel of asphalt (quarterly).

EUG 118 Process Heater (H-201). Emission limits and standards for EU H-201 are listed below. Emissions from H-201 are based on a maximum rated capacity (HHV) of 104.7 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H₂S concentration of 159 ppmdv. NO_x emissions from H-201 are based on the factor for post-NSPS units >100 MMBTUH.

EU	Point	Description	MMBTUH
H-201	P-119	Process Heater	104.7

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
19.65	85.67	8.65	37.87	0.78	3.43	3.53	15.44	0.57	2.48

- a. EU H-201 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
 - i. § 60.104 Standards for sulfur dioxide – (a)(1)
 - ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
 - iii. § 60.106 Test methods and procedures – (e)
- b. Emissions of NO_x from EU H-201 shall not exceed 0.2 lb/MMBTU. [OAC 252:100-33]
- c. Fuel use (SCF) and heat content (BTU/SCF) for EU H-201 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]
- d. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above.

EUG 120 Process Heater (H-401A). Emission limits and standards for EU H-401A are listed below. Emissions from H-401A are based on a maximum rated capacity (HHV) of 16.0 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H₂S concentration of 159 ppm_{dv}.

EU	Point	Description	MMBTUH
H-401A	P-121	Process Heater	16.0

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1.57	6.87	1.32	5.77	0.12	0.52	0.54	2.35	0.09	0.38

EUG 121 Process Heater (H-401B). Emission limits and standards for EU H-401B are listed below. Emissions from H-401B are based on a maximum rated capacity (HHV) of 17.0 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H₂S concentration of 159 ppm_{dv}.

EU	Point	Description	MMBTUH
H-401B	P-122	Process Heater	17.0

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1.67	7.30	1.40	6.13	0.13	0.55	0.57	2.49	0.09	0.40

- a. EU H-401B is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
- i. § 60.104 Standards for sulfur dioxide – (a)(1)
 - ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
 - iii. § 60.106 Test methods and procedures – (e)

EUG 122 Process Heater (H-402A). Emission limits and standards for EU H-402A are listed below. Emissions from H-402A are based on a maximum rated capacity (HHV) of 13.8 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H₂S concentration of 159 ppm_{dv}.

EU	Point	Description	MMBTUH
H-402A	P-123	Process Heater	13.8

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1.35	5.93	1.14	4.98	0.10	0.45	0.46	2.03	0.07	0.33

EUG 123 Process Heater (H-402B). Emission limits and standards for EU H-402B are listed below. Emissions from H-402B are based on a maximum rated capacity (HHV) of 15.9 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H₂S concentration of 159 ppm_{dv}.

EU	Point	Description	MMBTUH
H-402B	P-124	Process Heater	15.9

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1.56	6.83	1.31	5.74	0.12	0.52	0.53	2.33	0.09	0.38

EUG 124 Process Heater (H-407). Emission limits and standards for EU H-407 are listed below. Emissions from H-407 are based on a maximum rated capacity (HHV) of 25.0 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H₂S concentration of 159 ppm_{dv}.

EU	Point	Description	MMBTUH
H-407	P-125	Process Heater	25.0

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
2.45	10.74	2.06	9.02	0.19	0.82	0.84	3.67	0.13	0.59

- a. EU H-407 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
- i. § 60.104 Standards for sulfur dioxide – (a)(1)
 - ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
 - iii. § 60.106 Test methods and procedures – (e)

EUG 126 Boiler (B-802). Emission limits and standards for EU B-802 are listed below. Emissions from B-802 are based on a maximum rated capacity (HHV) of 77.8 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H₂S concentration of 159 ppm_{dv}.

EU	Point	Description	MMBTUH
B-802	P-127	Boiler	77.8

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
7.63	33.41	6.41	28.06	0.58	2.54	2.61	11.42	0.42	1.84

- a. EU B-802 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
- i. § 60.104 Standards for sulfur dioxide – (a)(1)
 - ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
 - iii. § 60.106 Test methods and procedures – (e)

EUG 127 Boiler (B-803). Emission limits and standards for EU B-803 are listed below. Emissions from B-803 are based on a maximum rated capacity (HHV) of 75.9 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H₂S concentration of 159 ppm_{dv}.

EU	Point	Description	MMBTUH
B-803	P-128	Boiler	75.9

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
7.44	32.59	6.25	27.38	0.57	2.48	2.54	11.14	0.41	1.79

- a. EU B-803 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
- i. § 60.104 Standards for sulfur dioxide – (a)(1)
 - ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
 - iii. § 60.106 Test methods and procedures – (e)

EUG 128 Process Heater (H-411). Emission limits and standards for EU H-411 are listed below. Emissions from H-411 are based on a maximum rated capacity (HHV) of 28 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H₂S concentration of 159 ppm_{dv}.

EU	Point	Description	MMBTUH
H-411	P-129	Process Heater	28.0

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
2.75	12.02	2.31	10.10	0.21	0.91	0.94	4.11	0.15	0.66

- a. EU H-411 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
- i. § 60.104 Standards for sulfur dioxide – (a)(1)
 - ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
 - iii. § 60.106 Test methods and procedures – (e)

EUG 134 Process Flare (HI-81001). Emission limits and standards for EU HI-81001 are listed below. Emissions from HI-81001 are based on a maximum rated capacity (HHV) of 27 MMBTUH, the respective emissions factors from AP-42, Section 13.5 (1/95), and a fuel gas H₂S concentration of 159 ppmv.

EU	Point	Description	MMBUH
HI-81001	P-135	Platformer and Alkylation Units	27

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1.90	8.34	10.36	45.38	0.27	1.20	0.94	4.11	3.92	17.17

- a. EU HI-81001 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
 - i. § 60.104 Standards for sulfur dioxide – (a)(1)
 - ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii) or other alternative monitoring approved per § 60.13.
 - iii. § 60.106 Test methods and procedures – (e)
- b. EU HI-81001 shall comply with all applicable requirements including but not limited to the following requirements: [40 CFR Parts 60 and 63]
 - i. EU HI-81001 shall meet the design requirements of 40 CFR Part 60 NSPS, Subpart A.
 - i. EU HI-81001 shall meet the design requirements of 40 CFR Part 63 NESHAP, Subpart A.

EUG 138 Process Heater (H-15001). Emission limits and standards for EU H-15001 are listed below. Emissions from H-15001 are based on a maximum rated capacity (HHV) of 293.3 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H₂S concentration of 159 ppmv, except for emissions of NO_x and CO which were based on an emission factor of 0.037 lb/MMBTU and 0.030 lb/MMBTU, respectively.

EU	Point	Description	MMBTUH
H-15001	P-139	Process Heater	293.3

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
10.85	47.53	8.80	38.54	2.19	9.57	9.83	43.04	1.58	6.93

- a. EU H-15001 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
 - i. § 60.104 Standards for sulfur dioxide – (a)(1)
 - ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
 - iii. § 60.106 Test methods and procedures – (e)
- b. EU H-15001 shall be operated with LNB.
- c. Emissions of NO_x from EU H-15001 shall not exceed 0.037 lb/MMBTU.

- d. Emissions of CO from EU H-15001 shall not exceed 0.030 lb/MMBTU.
- e. Fuel use (SCF) and heat content (BTU/SCF) for EU H-15001 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]
- f. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above.

EUG 139 Process Heater (H-210001). Emission limits and standards for EU H-210001 are listed below. Emissions from H-210001 are based on a maximum rated capacity (HHV) of 12.2 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H₂S concentration of 4 ppmv.

EU	Point	Description	MMBTUH
H-210001	P-140	Process Heater	12.2

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1.20	5.24	1.00	4.40	0.09	0.40	0.01	0.05	0.07	0.29

- a. EU H-210001 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
 - i. § 60.104 Standards for sulfur dioxide – (a)(1)
 - ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
 - iii. § 60.106 Test methods and procedures – (e)
- b. EU H-210001 is subject to New Source Performance Standards (NSPS), Subpart Dc and shall comply with all applicable provisions. [40 CFR Part 60, Subpart Dc]
 - i. The permittee shall record and maintain records of the amounts of each fuel combusted in EU H-210001 during each day. [40 CFR 60.48c(g)]
- c. EU H-210001 shall only be fired with commercial grade natural gas. [OAC 252:100-31]

EUG 140 Gasoline Loading Rack Vapor Combustor (Light Products Loading Terminal). Emission limits and standards for the Light Products Loading Terminal are listed below. Emissions from the Light Products Loading Terminal Vapor Combustor are based on the following: an hourly loading limit of 155,782 gallons/hour of gasoline/diesel; an annual loading limit of 22,525,714 bbl/yr of gasoline/diesel; and the following factors: VOC and CO: 10 mg/L loaded; NO_x: 4 mg/L loaded. Fugitive VOC emissions from the Light Products Loading Terminal are based on calculated loading losses and a 99.2% collection efficiency for gasoline.

EU	Point
Light Products Loading Terminal (LPLT)	P-141

Source	NO _x		CO		VOC	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Vapor Combustor	5.20	15.79	13.00	39.48	17.16	39.48
Fugitives	----	----	----	----	13.00	34.19

- a. The LPLT vapor combustor is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
 - i. § 60.104 Standards for sulfur dioxide – (a)(1)
 - ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii) or other alternative monitoring approved per § 60.13.
 - iii. § 60.106 Test methods and procedures – (e)
- b. The LPLT vapor combustor shall comply with all applicable requirements including but not limited to the following requirements: [40 CFR Part 63]
 - i. The vapor combustor shall meet the design requirements of 40 CFR Part 63 NESHAP, Subpart A.
- c. The amount of gasoline and diesel loaded at the Light Products Loading Rack shall not exceed 155,782 gallons/hr based on a daily average or 22,525,714 bbl/year based on a 12-month rolling average.
- d. The Light Products Loading Terminal is subject to NESHAP, 40 CFR Part 63, Subpart CC and shall comply with all applicable requirements. [40 CFR 63, NESHAP, Subpart CC]
 - i. §63.642 General Standards.
 - ii. §63.650 Gasoline Loading Rack Provisions.
 - iii. §63.654 Reporting and Recordkeeping Requirements.

EUG 141* FCCU Flue Gas Scrubber (FGS-200). Emission limits and standards for EU FGS-200 are listed below. Emissions from the FGS are based on a BACT analysis and a supplemental environmental project.

EU	Point	Description
FGS-200	P-142	FCCU No. 1 Regenerator/CO Boiler and FCCU No. 2 Regenerator

* - EUGs 141A, 141B, and 141C, will all be vented to this EUG and point upon completion of the modifications. EUG 145 will either be vented to this EUG or another wet scrubber.

NO _x		CO		PM ₁₀ *		SO ₂	
lb/hr	TPY**	lb/hr	TPY**	lb/hr	TPY**	lb/hr	TPY**
66.07	179.9	35.00	54.10	21.30	46.64	61.60	202.4

* - The PM₁₀ emission limits are based only on the front-half of the PM₁₀ sampling train.

** - Based on a 12-month rolling average.

- a. The new and existing CO Boilers shall be operated with LNB. [OAC 252:100-8-34]
- b. All of the FCCU feedstock with the exception of charge filter backwash shall be hydrotreated. [OAC 252:100-8-34]
- c. EU FGS-200 shall be equipped with a continuous emissions monitoring system (CEMS) for determining and recording NO_x emissions. [OAC 252:100-8-6(a)(3)]
- d. The permittee shall compute the 12-month rolling average NO_x emissions from EU FGS-200 using the monthly average monitored NO_x concentrations along with the monthly average dry-basis stack gas flow rate.
- e. The off-gases from the FCCU No. 1 Regenerator shall be combusted in a CO Boiler prior to being processed by the FGS to reduce emissions of CO. [OAC 252:100-8-34]

- f. The emissions of CO from the FCCU No. 1 Regenerator shall be reduced by use of complete secondary combustion of the waste gas generated. [OAC 252:100-35-2(b)]
 - i. Removal of 93% or more of the CO generated shall be considered equivalent to secondary combustion.
- g. The existing FCCU No. 1 Regenerator's CO Boiler and Incinerator shall be replaced by a new CO Boiler capable of handling all of the FCCU No. 1 Regenerator off-gases. The existing FCCU No. 1 Regenerator's CO Boiler shall be retrofitted with LNB and maintained in standby or limited supplemental service. The existing FCCU No. 1 Regenerator's Incinerator shall be decommissioned. [CO 02-007 (IV)(4)(B)]
- h. The FCCU No. 2 Regenerator shall be operated in full combustion regeneration mode to reduce emissions of CO. [OAC 252:100-8-34 & 100-35-2(b)]
- i. EU FGS-200 shall be equipped with a CEMS for determining and recording CO emissions. [OAC 252:100-8-6(a)(3)]
- j. The permittee shall compute the 12-month rolling average CO emissions from EU FGS-200 using the monthly average monitored CO concentrations along with the monthly average dry-basis stack gas flow rate.
- k. All off-gases from the FCCU No. 1 Regenerator/CO Boiler system and the FCCU No. 2 Regenerator shall be treated by a Wet Scrubber (WS) to control emissions of SO₂ from the FCCU. [OAC 252:100-8-34]
 - i. The WS shall be designed and operated with devices that reduce the amount of entrained water in the WS off-gases.
- l. EU FGS-200 shall be equipped with a CEMS for determining and recording SO₂ emissions. [OAC 252:100-8-6(a)(3)]
- m. The permittee shall compute the 12-month rolling average SO₂ emissions from EU FGS-200 using the monthly average monitored SO₂ concentrations along with the monthly average dry-basis stack gas flow rate.
- n. The FCCU No. 1 Regenerator shall be operated with dual cyclones and the FCCU No. 2 Regenerator shall be operated with tertiary cyclones. The cyclones are within the Regenerators and shall be used to reduce emissions of PM₁₀. [OAC 252:100-34]
- o. The permittee shall install monitors to continuously monitor and record the following parameters of the WS:
 - i. Liquid flow rate of the WS (24-hour average).
 - ii. Gas temperature and flow rate through the WS (24-hour average).
 - iii. Liquid to Gas Ratio of the WS (24-hour average).
 - iv. Pressure drop across the WS (24-hour average).
 - v. pH of the WS liquor (24-hour average).
 - vi. The gas flow rate can be determined through the use of other parametric monitoring such as coke production and combustion, flue-gas CO₂ concentration, flue-gas O₂ concentration, and other parameters that may be monitored.
 - vii. These parameters are parametric indicators of the WS desired control efficiency. The indicator ranges for these parameters shall be determined based on actual performance tests data established during the initial performance tests to determine the WS control efficiency.

- p. The FCCU is subject to NSPS, 40 CFR Part 60, Subpart J and shall comply with all applicable requirements. [40 CFR 60, NSPS, Subpart J]
- i. §60.102 Standard for particulate matter.
 - ii. §60.103 Standard for carbon monoxide.
 - iii. §60.104 Standard for sulfur oxides – (b-d).
 - iv. §60.105 Monitoring of emissions and operations – (a)(1), (a)(2), (a)(8-13), (c), (d), (e)(1), and (e)(2) or other alternative monitoring approved per § 60.13.
 - v. §60.106 Test Methods and Procedures(a-d) and (g-k).
 - vi. §60.107 Reporting and Recordkeeping Requirements (a-f).
 - vii. §60.108 Performance Test and Compliance Provisions (a-e).
- q. The FCCU will be subject to NESHAP, 40 CFR Part 63, Subpart UUU and shall comply with all applicable requirements by the dates specified in §63.1563(b). [40 CFR 63, NESHAP, Subpart UUU]

EUG 141A FCCU No. 1 Regenerator and CO Boiler/Incinerator (HI-251). The FCCU No. 1 Regenerator and CO Boiler will be vented to the WS and all emissions are associated with EU FGS-200. The FCCU No. 1 Incinerator will be decommissioned.

EU	Point	Description
HI-251	P-143	FCCU No. 1 Regenerator and CO Boiler/Incinerator

- a. All emissions from the FCCU No. 1 Regenerator shall be processed through a CO Boiler (EU B-253 or B-252) and then vented through the FCCU FGS. [OAC 252:100-8-34]
- b. The FCCU No. 1 Incinerator shall be decommissioned. [CO 02-007 (IV)(4)(B)]

EUG 141B CO Boilers (B-252 and B-253). The CO Boilers are vented to the WS and all emissions are associated with EU FGS-200.

EU	Point	Description	MMBTUH
B-252	P-143	CO Boiler	92.0
B-253	P-143	CO Boiler	125.8

- a. The CO Boilers shall be vented to the FCCU WS. [OAC 252:100-8-34]
- b. The CO Boilers shall be equipped with LNB. [OAC 252:100-8-34]
- c. All emissions from the FCCU No. 1 Regenerator shall be processed through EU B-253.
- d. EU B-252 shall be maintained in standby or limited supplemental service. [CO 02-007 (IV)(4)(B)]
- e. EU B-252 and B-253 are subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
 - i. § 60.104 Standards for sulfur dioxide – (a)(1)
 - ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
 - iii. § 60.106 Test methods and procedures – (e)

- f. EU B-252 is subject to New Source Performance Standards (NSPS), Subpart Dc and shall comply with all applicable provisions. [40 CFR Part 60, Subpart Dc]
 - i. The permittee shall record and maintain records of the amounts of each fuel combusted in EU B-252 during each day. [40 CFR 60.48c(g)]
- g. EU B-253 is subject to New Source Performance Standards (NSPS), Subpart Db and shall comply with all applicable provisions. [40 CFR Part 60, Subpart Db]
 - i. § 60.44b Standard for Nitrogen Oxides – (e), (f), (h), (i), (j), (k)
 - ii. § 60.46b Compliance and Performance Test Methods and Procedures for Nitrogen Oxides – (c), (e), (g)
 - iii. § 60.48b Emission monitoring for Nitrogen Oxides – (b), (c), (d), (e), (f), (g), (h), (i)
 - iv. § 60.49b Reporting and Recordkeeping Requirements (a) through (p)

EUG 141C FCCU No. 2 Regenerator (R-251). The FCCU No. 2 Regenerator is vented to the WS and all emissions are associated with EU FGS-200.

EU	Point	Description
R-251	P-142	FCCU No. 2 Regenerator

- a. The FCCU No. 2 Regenerator shall be operated in full combustion regeneration mode. [OAC 252:100-8-34 & 100-35-2(b)]
- b. The FCCU No. 2 Regenerator shall be vented to the FCCU WS. [OAC 252:100-8-34]

EUG 145 FCCU Catalyst Hopper Vent (cat_hop). Emissions limits for the FCCU Catalyst Hoppers are based on venting emissions to a WS or equally effective control device.

EU	Point	Description
cat_hop	P-149	FCCU Catalyst Hopper Vent

PM₁₀
TPY
1.88

- a. The FCCU Catalyst Hoppers shall be vented through a cyclone and then to the FCCU WS (FGS-200) or another equally effective control device. [OAC 252:100-8-34]
- b. If the permittee does not vent the FCCU Catalyst Hoppers to the FCCU WS, the permittee shall monitor and record the following parameters of the WS or other parameters as necessary to ensure compliance with the emission limit above:
 - i. Liquid flow rate of the WS (24-hour average).
 - ii. Pressure drop across the WS (24-hour average).
 - iii. These parameters are parametric indicators of the WS desired control efficiency. The indicator ranges for these parameters shall be determined based on actual performance test data established during the initial performance tests to determine the WS control efficiency.

EUG 143 Emergency Generators (EEQ-8801 and EEQ-80001). Emission limits and standards for EU EEQ-8801 and EEQ-80001 are listed below. Emissions from the emergency generators are based on 800 hours of operation a year, a diesel fuel heating value of 19,500 BTU/lb, a fuel sulfur content of 0.05% by weight, and the following:

EEQ-8801 - A maximum fuel input of 461.5 lb/hr and the respective emissions factors from AP-42, Section 3.3 (10/96);

EEQ-80001 - A maximum fuel input of 106.5 lb/hr and the respective emissions factors from AP-42, Section 3.4 (10/96).

EU	Point	Make/Model	KW	Serial #
EEQ-8801	P-145	DMT/DMT-825D2	750	93447-1
EEQ-80001	P-146	Cummins/6BT5.9G-2	80	45555233

	NO _x		CO		PM ₁₀		SO ₂		VOC	
EEQ	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
8801	28.80	11.52	7.65	3.06	0.52	0.21	0.45	0.18	0.74	0.29
80001	9.16	3.66	1.97	0.79	0.64	0.26	0.10	0.04	0.75	0.30

- EU EEQ-8801 and EEQ-80001 shall not operate more than 800 hours per year.
- EU EEQ-8801 and EEQ-80001 shall be fitted with non-resettable hour-meters.
- The sulfur content of the fuel for EU EEQ-8801 and EEQ-80001 shall not exceed 0.05% by weight (on-road low-sulfur diesel performance specification). [OAC 252:100-31]
- The permittee shall maintain records of the diesel fuel purchase receipts documenting the sulfur content for each delivery of diesel fuel or shall determine and record the fuel sulfur content for each delivery of diesel fuel for the generators. [OAC 252:100-45]
- A serial number or another acceptable form of permanent (non-removable) identification shall be on each generator.

EUG 146 Platformer Catalyst Regeneration Vent (CCR). Emission limits and standards for EU CCR are listed below. Emissions from the CCR are based on a coke-burning rate of 49 lbs/hr, which is equivalent to a maximum catalyst recirculation rate of 700 lb/hr and a coke combustion rate of 7% of the catalyst processing rate (700 lb/hr @ 7% wt), with a coke maximum sulfur content of 0.5% by weight. Coke combustion emissions were based on the respective emissions factors from AP-42 (1/95), Section 1.1, for sub-bituminous coal combustion. PM₁₀ emissions also include a recovery factor for the catalyst of 99.99%.

EU	Point	Description
CCR	P-150	Platformer Catalyst Regeneration Combustion Vent

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
0.83	3.65	0.12	0.54	0.39	1.73	0.47	2.04	0.03	0.14

- a. The catalyst recirculation rate shall not exceed 700 lb/hr. [OAC 252:100-8-6(a)(1)]
- b. The emissions of CO from the CCR shall be reduced by use of complete secondary combustion of the waste gas generated. [OAC 252:100-35-2(b)]
 - i. Removal of 93% or more of the CO generated shall be considered equivalent to secondary combustion.
- c. The sulfur content of the Platformer feed shall not exceed 5 ppmw. [OAC 252:100-8-6(a)(1)]
- d. The permittee shall determine and record the sulfur content of the CCR feed (quarterly). [OAC 252:100-45]
- e. The CCR will be subject to NESHAP, 40 CFR Part 63, Subpart UUU and shall comply with all applicable requirements by the dates specified in §63.1563(b). [40 CFR 63, NESHAP, Subpart UUU]

EUG 147 Instrument/Plant Air Compressor (C-80018). Emission limits and standards for EU C-80018 are listed below. Emissions from C-80018 are based on 4,000 hours of operation a year, a horsepower rating of 400-hp, the respective emissions factors from AP-42, Section 3.3 (10/96), and a fuel sulfur content of 0.05% by weight.

EU	Point	Make/Model	Hp	Serial #	Const. Date
C-80018	P-151	General/250004-A36	400	69102	1993

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
12.40	24.80	2.67	5.34	0.88	1.76	0.14	0.28	1.01	2.01

- a. EU C-80018 shall not operate more than 4,000 hours per year.
- b. EU C-80018 shall be fitted with a non-resettable hour-meter.
- c. The sulfur content of the fuel for EU C-80018 shall not exceed 0.05% by weight. (on-road low-sulfur diesel performance specification) [OAC 252:100-31]
- d. The permittee shall maintain records of the diesel fuel purchase receipts documenting the sulfur content for each delivery of diesel fuel or shall determine and record the fuel sulfur content for each delivery of diesel fuel for the Instrument/Plant Air Compressor. [OAC 252:100-45]
- e. EU C-80018 shall be equipped with permanent (non-removable) identification such as a serial number or another acceptable form of identification.
- f. Placement of EU C-80018 shall be limited to the north end of the FCCU area. [OAC 252:100-3]

EUG 148 Process Heater (H-100024). Emission limits and standards for EU H-100024 are listed below. Emissions from H-100024 are based on a maximum rated capacity (HHV) of 13.5 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H₂S concentration of 159 ppmv.

EU	Point	Description	MMBTUH
H-100024	P-152	Asphalt Tank Heater	13.5

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	Lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
0.68	2.96	1.11	4.87	0.10	0.44	0.45	1.98	0.07	0.32

- h. EU H-100024 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
- i. § 60.104 Standards for sulfur dioxide – (a)(1)
 - ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
 - iii. § 60.106 Test methods and procedures – (e)
- i. EU H-100024 is subject to New Source Performance Standards (NSPS), Subpart Dc and shall comply with all applicable provisions. [40 CFR Part 60, Subpart Dc]
- i. The permittee shall record and maintain records of the amounts of each fuel combusted in EU H-100024 during each day. [40 CFR 60.48c(g)]

EUG 200 Crude Unit Fugitive Sources (Area 100). Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable Leak Detection and Repair (LDAR) program.

EU	Point	Number Items	Type of Equipment
Area 100	F-100	2,338	Valves
		3,876	Flanges
		15	Other
		46	Pumps

- a. All affected equipment, in HAP service (contacting >5% by weight HAP), shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component.
- i. §63.642 General Standards
 - ii. §63.648 Equipment Leak Standards
 - iii. §63.654 Reporting and Recordkeeping Requirements
- b. Equipment determined not to be in HAP service (contacting <5% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG.
- i. §60.592 Standards
 - ii. §60.593 Exceptions

EUG 205 Amine Fuel Gas Treating System Fugitive Sources (Area 550). Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR program.

EU	Point	Number Items	Type of Equipment
Area 550	F-105	403	Valves
		677	Flanges
		4	Other
		11	Pumps

- a. All affected equipment, in HAP service (contacting >5% by weight HAP), shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component.
 - i. §63.642 General Standards
 - ii. §63.648 Equipment Leak Standards
 - iii. §63.654 Reporting and Recordkeeping Requirements
- b. Equipment determined not to be in HAP service (contacting <5% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG.
 - i. §60.592 Standards
 - ii. §60.593 Exceptions

EUG 206 Saturates Gas Plant Fugitive Sources (Area 300). Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR program.

EU	Point	Number Items	Type of Equipment
Area 300	F-106	835	Valves
		1,389	Flanges
		12	Other
		7	Pumps

- a. All affected equipment, in HAP service (contacting >5% by weight HAP), shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component.
 - i. §63.642 General Standards
 - ii. §63.648 Equipment Leak Standards
 - iii. §63.654 Reporting and Recordkeeping Requirements
- b. Equipment determined not to be in HAP service (contacting <5% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG.
 - i. §60.592 Standards
 - ii. §60.593 Exceptions

EUG 207 Reformer “Platformer” Fugitive Sources (Area 400). Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR program.

EU	Point	Number Items	Type of Equipment
Area 400	F-107	2,074	Valves
		3,488	Flanges
		23	Other
		16	Pumps

- a. All affected equipment, in HAP service (contacting >5% by weight HAP), shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component.
 - i. §63.642 General Standards
 - ii. §63.648 Equipment Leak Standards
 - iii. §63.654 Reporting and Recordkeeping Requirements
- b. Equipment determined not to be in HAP service (contacting <5% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG.
 - i. §60.592 Standards
 - ii. §60.593 Exceptions

EUG 208 Isomerization Unit Fugitive Sources (Area 450). Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR program.

EU	Point	Number Items	Type of Equipment
Area 450	F-108	786	Valves
		1,294	Flanges
		17	Other
		5	Pumps

- a. All affected equipment, in HAP service (contacting >5% by weight HAP), shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component.
 - i. §63.642 General Standards
 - ii. §63.648 Equipment Leak Standards
 - iii. §63.654 Reporting and Recordkeeping Requirements
- b. Equipment determined not to be in HAP service (contacting <5% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG.
 - i. §60.592 Standards
 - ii. §60.593 Exceptions

EUG 211 HF Alkylation Unit Fugitive Sources (Area 211). Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR program.

EU	Point	Number Items	Type of Equipment
Area 900	F-111	2,295	Valves
		3,803	Flanges
		23	Other
		31	Pumps

- a. All affected equipment, in HAP service (contacting >5% by weight HAP), shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component.
 - i. §63.642 General Standards
 - ii. §63.648 Equipment Leak Standards
 - iii. §63.654 Reporting and Recordkeeping Requirements
- b. Equipment determined not to be in HAP service (contacting <5% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG.
 - i. §60.592 Standards
 - ii. §60.593 Exceptions

EUG 214 Wastewater Treatment Unit Fugitive Sources (ASU). Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR programs.

EU	Point	Number Items	Type of Equipment
ASU	F-114	154	Valves
		258	Flanges
		---	Other
		6	Pumps

- a. All affected equipment, in HAP service (contacting >5% by weight HAP), shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component.
 - i. §63.642 General Standards
 - ii. §63.648 Equipment Leak Standards
 - iii. §63.654 Reporting and Recordkeeping Requirements
- b. Equipment determined not to be in HAP service (contacting <5% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG.
 - i. §60.592 Standards
 - ii. §60.593 Exceptions

EUG 219 Olefin Treating Unit Fugitive VOC Emissions (Area 250). Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR program.

EU	Point	Number Items	Type of Equipment
Area 250	F-119	1,118	Valves
		969	Flanges
		5	Other
		12	Pumps

- a. All affected equipment, in HAP service (contacting >5% by weight HAP), shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component.
 - i. §63.642 General Standards
 - ii. §63.648 Equipment Leak Standards
 - iii. §63.654 Reporting and Recordkeeping Requirements
- b. Equipment determined not to be in HAP service (contacting <5% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG.
 - i. §60.592 Standards
 - ii. §60.593 Exceptions

3. Certain equipment within the refinery is subject to NSPS, 40 CFR Part 60, Subpart QQQ and all affected equipment shall comply with all applicable requirements.

[40 CFR 60, NSPS, Subpart QQQ]

- a. § 60.692–1 Standards: General.
- b. § 60.692–2 Standards: Individual drain systems.
- c. § 60.692–3 Standards: Oil-water separators.
- d. § 60.692–4 Standards: Aggregate facility.
- e. § 60.692–5 Standards: Closed vent systems and control devices.
- f. § 60.692–6 Standards: Delay of repair.
- g. § 60.692–7 Standards: Delay of compliance.
- h. § 60.693–1 Alternative standards for individual drain systems.
- i. § 60.693–2 Alternative standards for oil-water separators.
- j. § 60.695 Monitoring of operations.
- k. § 60.696 Performance test methods and procedures and compliance provisions.
- l. § 60.697 Recordkeeping requirements.
- m. § 60.698 Reporting requirements.

4. The Refinery is subject to NESHAP, 40 CFR Part 61, Subpart FF and shall comply with all applicable requirements. [40 CFR 61, NESHAP, Subpart FF]

- a. § 61.342 Standards: General.
- b. § 61.343 Standards: Tanks.
- c. § 61.344 Standards: Surface Impoundments.
- d. § 61.345 Standards: Containers.
- e. § 61.346 Standards: Individual drain systems.
- f. § 61.347 Standards: Oil-water separators.
- g. § 61.348 Standards: Treatment processes.
- h. § 61.349 Standards: Closed-vent systems and control devices.
- i. § 61.350 Standards: Delay of repair.
- j. § 61.351 Alternative standards for tanks.
- k. § 61.352 Alternative standards for oilwater separators.
- l. § 61.353 Alternative means of emission limitation.
- m. § 61.354 Monitoring of operations.
- n. § 61.355 Test methods, procedures, and compliance provisions.
- o. § 61.356 Recordkeeping requirements.
- p. § 61.357 Reporting requirements.

5. Certain equipment within the refinery is subject to NESHAP, 40 CFR Part 63, Subpart CC and all affected equipment shall comply with all applicable requirements including but not limited to: [40 CFR 63, NESHAP, Subpart CC]

- a. § 63.642 General Standards
- b. § 63.643 Miscellaneous Process Vent Provisions
- c. § 63.644 Monitoring for Miscellaneous Process Vents
- d. § 63.645 Test Methods and Procedures for Miscellaneous Process Vents
- e. § 63.646 Storage Vessel Provisions
- f. § 63.647 Wastewater Provisions
- g. § 63.648 Equipment Leak Standards
- h. § 63.652 Emission Averaging Provisions
- i. § 63.653 Monitoring, Recordkeeping, and Implementation Plan for Emissions Averaging
- j. § 63.654 Reporting and Recordkeeping Requirements
- k. The permittee shall comply with the provisions of 40 CFR Part 63 Subpart A as specified in Appendix to Subpart CC, Table 6.

6. Within 60 days of achieving start-up of the WS on the FCCU, not to exceed 180 days from initial start-up, and at other such times as directed by Air Quality, the permittee shall conduct performance testing as follows and furnish a written report to Air Quality. Such report shall document compliance with all specific conditions and applicable requirements.

[OAC 252:100-8-6(a)(3)]

- a. The permittee shall conduct NO_x, CO, PM₁₀, and SO₂ testing on the FCCU within 90% of the permitted maximum feedstock flowrate. Performance testing shall include determination of the nitrogen and sulfur content of the FCCU feedstock.

- b. If the FCCU Catalyst Hoppers are not vented to the FCCU WS, the permittee shall conduct PM₁₀ testing on the control device for the FCCU Catalyst Hoppers during actual operation/loading of the FCCU Catalyst Hoppers.
 - c. The permittee shall conduct NO_x emission testing on EU H-201 within 90% of the permitted maximum rated heat input.
 - d. The permittee shall conduct NO_x and CO emission testing on C-80018 within 90% of the maximum rated load. Testing for the engine can be conducted using portable engine analyzers or an equivalent method approved by Air Quality.
 - e. The permittee may report all PM emissions measured by USEPA Method 5B as PM₁₀, including back half condensable particulate. If the permittee reports USEPA Method 5B PM emissions as PM₁₀, testing using USEPA Method 201 or 201A need not be performed. Compliance with the BACT emission limits shall be determined using only the front-half of the PM₁₀ sampling train. Compliance with the emission limits established by OAC 252:100-19 shall be determined using the front-half and the back-half of the PM₁₀ sampling train.
 - f. Testing protocols shall be submitted to the Air Quality Division describing the required testing. The permittee shall provide a copy of the testing protocol, and notice of the actual test date, to AQD for review and approval at least 30 days prior to the start of such testing.
 - g. The permittee shall use any approved USEPA test methods codified in 40 CFR Part 60 Appendix A, for testing of emissions, unless otherwise approved by Air Quality.
 - h. All CEMS shall meet the performance specifications codified in 40 CFR Part 60 Appendix B unless otherwise approved by Air Quality.
 - i. Testing conducted under this specific condition shall be used to certify the CEMS.
7. The permittee shall conduct daily visual observations of the opacity from the EU HI-801, and CCR exhausts and keep a record of these observations. In no case, shall the observation period be less than six minutes in duration. If visible emissions are observed for six minutes in duration for any observation period and such emissions are not the result of a malfunction, then the permittee shall conduct, within 24 hours, a visual observation of emissions, in accordance with 40 CFR Part 60, Appendix A, Method 9. [OAC 252:100-25]
- a. When five consecutive daily visible emission observations or Method 9 observations show no visible emissions, or no emissions of a shade or density greater than twenty (20) percent equivalent opacity, respectively, the frequency may be reduced to weekly visual observations, as above. Likewise, when the following four consecutive weekly observations show compliance, the observation frequency may be reduced to monthly observations. Upon any showing of non-compliance the observation frequency shall revert to daily.
 - b. If a Method 9 observation exceeds 20% opacity the permittee shall conduct at least two additional Method 9 observations within the next 24-hours.
 - c. If more than one six-minute Method 9 observation exceeds 20% opacity in any consecutive 60 minutes; or more than three six-minute Method 9 observations in any consecutive 24 hours exceeds 20% opacity; or if any six-minute Method 9 observation exceeds 60% opacity; the owner or operator shall comply with the provisions for excess emissions during start-up, shut-down, and malfunction of air pollution control equipment.

8. Until 12 consecutive months of data has been collected to determine the 12-month rolling averages applicable to the facility, the facility shall fill the missing data for the previous months with an estimated average monthly figure based on the applicable rolling average divided by 12. If there exists enough data to determine the values for the previous months, it can be used to determine the applicable 12-month rolling averages. [OAC 252:100-8-6(a)(3)]

9. The permittee shall maintain records as specified in Specific Condition 1 and 2 including but not limited to those listed below. These records shall be maintained on-site for at least five years after the date of recording and shall be provided to regulatory personnel upon request. [OAC 252:100-43]

- a. Operating hours for EU EEQ-8801, EEQ-80001, C-80018 (monthly and 12-month rolling average).
- b. Compliance with all applicable 12-month rolling averages (monthly).
- c. Throughput of the loading rack (daily).
- d. CEMS data as required.
- e. Records required by NSPS, Subparts Dc, Kb, J, GGG, and QQQ and NESHAP, Subparts FF and CC.
- f. Visible emission observations (date, time, and reading).

10. When monitoring shows an exceedance of any of the limits of Specific Condition No. 2, the owner or operator shall comply with the provisions of OAC 252:100-9 for excess emissions. [OAC 252:100-9]

11. The permittee shall implement the BACT and the SEP for the FCCU No. 1 and No. 2 Regenerators, CO Boiler, and the FCCU Catalyst Receiving Hopper as specified in Specific Condition 2, Consent Order (CO) 02-007, and the approved BACT report dated April 18, 2000. These BACT controls shall be installed according to the following schedule:

- a. Design engineering of the relevant BACT controls shall be completed within 90 days of issuance of this permit.
- b. Construction of the relevant BACT controls shall be completed within 28 months of issuance of this permit.
- c. Performance testing and submittal to Air Quality of a report documenting compliance with this permit, following a reasonable shakedown period for the installed controls, shall not exceed 180 days after completion of construction of the BACT. [CO 02-007 (IV)(3)(C)(3) and (4) and (IV)(4)(B)]

12. The permittee shall implement the BACT for the Crude Unit Equipment Fugitive Emissions as specified in Specific Condition 2 and the approved BACT report dated April 18, 2000. The BACT controls shall be implemented according to the following schedule:

- a. Implementation of the relevant BACT controls shall be completed within 30 days of issuance of this permit.

- b. Performance testing and submittal to Air Quality of a report documenting compliance with this permit shall be completed within 60 days of issuance of this permit.

[CO 02-007 (IV)(3)(C)(2)]

13. The permittee shall submit to Air Quality a new/updated Part 70 permit application, within 180 days after performance testing conducted in accordance with this permit. With this permit update, the permittee shall submit to Air Quality a CAM plan in accordance with 40 CFR Part 64 for the BACT controls installed and implemented for Heaters 102A and 102B, Crude Unit fugitive VOCs, the FCCU No. 1 and No. 2 Regenerators and CO Boiler, and the FCCU Catalyst Receiving Hopper.

[CO 02-007 (IV)(3)(C)(5)]

14. Unless otherwise provided by the AQD, the permittee shall, within 90 days of issuance of this permit, submit a plan, program, and schedule setting forth all activities necessary to achieve compliance with all applicable PSD and NSPS requirements set forth in Administrative Order 02-007 (Compliance Plan). The Compliance Plan shall include specific dates by which:

- a. Design information applicable to emission control devices to be installed/constructed will be submitted to DEQ;
- b. Contracts for fabrication and installation of said control device systems will be let and completed;
- c. Initial startup, testing and shakedown of said control device systems will be commenced and completed; and
- d. Final compliance with all applicable conditions of the permit and consent order will be achieved.

[CO 02-007 (IV)(3)(G)]

15. The Refinery shall, within 90 days after submittal of the CAM plan and Part 70 permit application referenced in Specific Condition 12 to Air Quality, submit a Compliance Certification demonstrating compliance with all applicable PSD and minor source permitting, NSPS, Part 70 permitting and CAM plan requirements set forth in this permit and CO 02-007.

[CO 02-007 (IV)(3)(H)]

16. The permittee shall submit to DEQ quarterly progress reports summarizing activities undertaken pursuant to this permit and CO 02-007 for the preceding quarter and projecting activities for the ensuing quarter. The first report shall be submitted within 45 days after the conclusion of the first full calendar quarter following the Effective Date of CO 02-007 (March 7, 2002). The report for each quarter thereafter shall be submitted within 45 days after the expiration of such quarter.

[CO 02-007 (IV)(3)(I)]

17. Within 180 days of issuance of this permit, the permittee shall submit plans for post-construction ambient air monitoring of PM₁₀ (24-hour impact). Deficiencies in the monitoring plan shall be corrected within 90 days of notification of acceptability of the monitoring plan. Monitoring shall be commenced with 180 days of start-up of the facility and shall be conducted for a period of at least 12 consecutive months.

[OAC 252:100-8-35(d)(5)]

Valero Energy Corporation
TPI Petroleum, Inc.
Attn: Mr. John Shriver, P.E.
Environmental Manager
Post Office Box 188
Ardmore, OK 74302

Re: Construction Permit No. **98-172-C (PSD)**
Valero Ardmore Refinery - Administrative Consent Order No. 02-007
Ardmore, Carter County

Dear Mr. Shriver:

Enclosed is the permit authorizing construction/modification of the referenced facility. Please note that this permit is issued subject to the certain standards and specific conditions, which are attached. These conditions must be carefully followed since they define the limits of the permit and will be confirmed by periodic inspections.

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact me at (405) 702-4217.

Sincerely,

Eric L. Milligan, P.E.
Engineering Section
AIR QUALITY DIVISION

enclosures